FORTIS BC™

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

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

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

August 29, 2011

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

Attention: Ms. Alanna Gillis, Acting Commission Secretary

Dear Ms. Gillis:

Re: An Inquiry into FortisBC Energy Inc. Regarding the Offering of Products and Services in Alternative Energy Solutions and Other New Initiatives (the "Inquiry")

Evidence of the FortisBC Energy Utilities

The FortisBC Energy Utilities ("FEU")[1] are pleased to file our Inquiry Evidence of the FortisBC Energy Utilities pursuant to Order No. G-118-11 (the "Scoping Order") issued by the British Columbia Utilities Commission (the "Commission") in the above noted proceeding.

The Scoping Order defines the scope and issues for the Inquiry in terms of "AES and other new initiatives", and specifically identifies FEI's Energy Efficiency and Conservation ("EEC") program as also within the scope of the Inquiry. The FEU have understood and interpreted the phrase "AES and other new initiatives" as concerning:

- The FEU's ownership of facilities that upgrade raw biogas into biomethane for the purpose of sale to customers of the FEU under the Biomethane Service;
- Natural gas vehicle ("NGV") fueling service, which involves the provision of Compressed Natural Gas ("CNG") and Liquified Natural Gas ("LNG") to customers under service agreements ("CNG/LNG Service"); and
- Thermal Energy Systems ("TES") offered under of the FEI General Terms & Conditions ("GT&Cs") Section 12A: Alternative Energy Extensions[2].

In this Filing, the FEU refer to Biomethane Service, NGV Service, TES *and also EEC,* collectively, as the "New Initiatives". This Filing provides the FEU's evidence of the drivers behind the New Initiatives, a description of New Initiatives being carried out by the FEU, including the regulatory history of the programs and the Commission's decisions approving

[1] The FEU are FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI"), and FortisBC Energy (Whistler) Inc. ("FEW").

[2] The FEU now use the term Thermal Energy Systems ("TES") to describe what was formerly known as "Alternative Energy Services" ("AES"), as TES is more descriptive. TES is the term used generally in this Filing.

the programs. It also provides the FEU's proposed guidelines in response to the specific issues identified by the Commission in Appendix A to the Scoping Order[3]. The FEU believe that the proposed guidelines, if adopted on a prospective basis, will provide clarity for the benefit of all stakeholders, and enhance the efficiency of regulatory processes dealing with the New Initiatives.

The FEU welcome the opportunity to review the New Initiatives with the Commission and interested stakeholders, and look forward to participating in a constructive and forward-looking Inquiry process.

If you have any questions regarding this Filing, please contact Shawn Hill at (604) 592-7840.

Yours very truly,

on behalf of the FORTISBC ENERGY UTILITIES

Original signed by: Shawn Hill

For: Diane Roy

Attachment

cc: Registered Parties

[3] Order No. G-118-11, Appendix A, pp. 7-8.

Before the British Columbia Utilities Commission

An Inquiry into FortisBC Energy Inc.
Regarding the Offering of Products and Services in Alternative Energy Solutions and Other New Initiatives

Evidence of
the FortisBC Energy Utilities

August 29, 2011

TABLE OF CONTENTS

LIST OF APPENDICES

1 INTRODUCTION AND EXECUTIVE SUMMARY

Order No. G-118-11 (the "Scoping Order") of the British Columbia Utilities Commission (the "Commission" or the "BCUC") established the scope and issues for an inquiry into the FortisBC Energy Utilities' (the "FEU" or the "Companies")[1] involvement in the provision of alternative energy services ("AES") and other new initiatives. The FEU are filing this evidence (the "Filing" or "Submission") pursuant to the Scoping Order. The Scoping Order defines the scope and issues for the Inquiry in terms of "AES and other new initiatives", and specifically identifies FEI's Energy Efficiency and Conservation ("EEC") program as also within the scope of the Inquiry. The FEU have understood the phrase "AES and other new initiatives" to relate to:

- The FEU's ownership of facilities that upgrade raw biogas into biomethane for the purpose of sale to the FEU customers under the Biomethane Service ("Biomethane upgrading");
- Natural gas vehicle ("NGV") fueling service, which involves the provision of Compressed Natural Gas ("CNG") and Liquified Natural Gas ("LNG") to customers under service agreements ("CNG/LNG Service"); and
- Thermal Energy Systems or Thermal Energy Services ("TES") or projects offered under of the FEI General Terms & Conditions ("GT&Cs") Section 12A: Alternative Energy Extensions[2].

In this Filing, the FEU refer to all four of these initiatives - Biomethane Service, NGV Service, TES *and also EEC* - collectively, as the "New Initiatives".

The Scoping Order states that the Inquiry is not to be used as a vehicle to re-open past decisions of the Commission[3]. Rather, the Inquiry is intended to be:

> *"… a forward looking assessment with the aim to establish principles that can be applied to future regulatory processes in the area of AES and other new initiatives."*[4]

This Filing provides the FEU's evidence of the drivers behind the New Initiatives, and the nature of the programs through which the New Initiatives are being carried out by the FEU, including the regulatory history of the programs and the Commission's decisions approving the programs.

---

1 The FEU are FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI"), and FortisBC Energy (Whistler) Inc. ("FEW")
2 The FEU now use the term Thermal Energy Systems ("TES") to describe what was formerly known as "Alternative Energy Services", as TES is more descriptive. TES is the term used generally in this Filing. For a copy of the FEI GT&Cs Section 12A refer to Appendix F.
3 Appendix A to Order No. G-118-11 (page 5).
4 Appendix B to Order No. G-118-11 (page 1).

This Filing also provides the FEU's proposed guidelines in response to the specific issues identified by the Commission in Appendix A to the Scoping Order[5].

The FEU continue to believe that natural gas has a significant role to play in meeting BC's energy requirements today and into the future because of its inherent physical properties, such as having the lowest emissions of the fossil fuels, no/low particulate matter, flexibility in end use applications, and abundant supply. Not all customers or stakeholders share the same view as the FEU. This makes for challenging times for the FEU to maintain our natural gas throughput in our traditional market segments, which is in the interests of customers and the Companies alike.

The FEU initially articulated their intention to pursue, Biomethane Service, NGV Service and TES in the 2008 Long-Term Resource Plan ("LTRP")[6]. At approximately the same time, the FEU filed a comprehensive EEC Application[7]. The FEU believe that there is a long-term role for natural gas in meeting energy demands for the Province, and identified the New Initiatives as appropriate responses to new challenges such as retaining and adding natural gas load for traditional end uses e.g. space and water heating, changing customer expectations, and the evolving energy policy and legislative environment.

Since the 2008 LTRP, the FEU have brought forward applications for approval of the New Initiatives pursuant to the provisions of the *Utilities Commission Act* (the "*UCA*" or the "*Act*"), and as contemplated in FEI's 2010-2011 Revenue Requirement Application ("RRA") Negotiated Settlement Agreement ("NSA"). By and large, the Commission's decisions have recognized, either expressly or implicitly, that the New Initiatives are regulated services under the provisions of the *Act*, and that they bring benefits to customers that are consistent with government policy. The proposed guidelines that the FEU have set out in Section 8 of this Filing are intended to reflect these previous decisions, and to ensure that future review of the New Initiatives is carried out in an efficient manner, ensuring that the interests of ratepayers, the broader public, and the FEU are considered in a meaningful way.

1.1 EXECUTIVE SUMMARY

What follows is an Executive Summary of the Filing, which generally tracks the organization of the evidence.

1.1.1 Why the FEU Are Pursuing the New Initiative

Section 2 of this Filing explains why the FEU are pursuing the New Initiatives. The New Initiatives, initially described in the 2008 LTRP, are the FEU's response to a rapidly changing energy environment, which challenges the traditional role of natural gas for heating applications over the long-term. Three general changes prompted the New Initiatives:

---

5 Appendix A to Order No. G-118-11 (pages 7-8).
6 Filed June 27, 2008.
7 EEC is a form of Demand-Side Management.

(a) a new energy environment where energy consumers increasingly have choices regarding energy sources and are interested in low-carbon solutions;

(b) a changing policy environment; and

(c) upward pressure on natural gas delivery rates caused by declining throughput levels.

A high-level summary of the drivers discussed in Section 2 is included below.

Traditionally, energy consumers were most concerned with the cost of energy, as opposed to how energy was delivered to their house or business. Over the past decade this attitude has changed in significant ways. More and more customers in the residential and commercial sectors are showing an interest in where energy comes from and how it is consumed.. Communities have begun to develop their own sustainability plans that involve looking at how energy should be used, and how energy decisions can be influenced through such means as bylaws, planning regulations, and building codes. The New Initiatives respond to this change in the energy environment by providing customers with energy alternatives that reduce Greenhouse Gas ("GHG") emissions, make use of renewable energy sources, and use innovative technologies that conserve energy, while at the same time making use of the existing natural gas infrastructure to the benefit of existing natural ratepayers.

Another key driver of the New Initiatives is the changing energy policy and legislative environment in British Columbia. The 2007 BC Energy Plan, amendments to the *Utilities Commission Act*, the *Carbon Tax Act*, and the *Clean Energy Act* have affirmed, among other things, the government's commitment to GHG emissions reduction, the use of renewable energy and innovative technologies, and the use of demand-side management. The legislative changes introduced to give effect to the 2007 BC Energy Plan have introduced new price signals, established GHG emissions reduction targets, and defined energy objectives that must be considered by the Commission when reviewing facility applications (Certificates of Public Convenience and Necessity ["CPCNs"]), expenditure schedules, long term resource plans, and the acquisition of energy supply. These changes, in turn, impact customer expectations by influencing how people think about their energy choices. The New Initiatives respond to this change in the energy environment by providing green energy solutions to customers that use renewable energy sources, make use of innovative technologies, and reduce GHG emissions. The New Initiatives are aligned with and advance British Columbia's energy objectives.

The changing customer expectations and policy environment, coupled with the public's perception of natural gas relative to other energy products (primarily British Columbia's clean and renewable electricity supply) have contributed to declining throughput on the natural gas system. The FEU's ability to retain and attract load and customers has an impact on natural gas delivery rates for existing customers; declining throughput drives higher delivery rates. The New Initiatives are a tool to attract new customers who might otherwise seek out other "green" energy sources, and to retain customers who may leave the FEU and natural gas for an alternative energy source. Each of the New Initiatives assists in different ways.

- The Biomethane Service responds to drivers discussed above (and further discussed in Section 2) by making use of existing infrastructure to provide customers with access to a renewable energy source, and helps to retain customers who might otherwise seek out other energy solutions. This, in turn, helps FEI maintain throughput levels, which benefits existing and future natural gas customers directly by favourably impacting delivery rates.

- The NGV Service responds to drivers discussed above (and further discussed in Section 2) by providing a cleaner energy solution that taps into a customer segment (transportation) that can add high load-factor throughput to make better use of the existing FEI infrastructure, while addressing the largest driver of GHG emissions in the Province. Increasing the throughput in this manner benefits existing and future natural gas customers of FEI by producing lower delivery rates than would otherwise be the case.

- TES responds to drivers discussed above (and further discussed in Section 2) by providing potential customers with an efficient, low-carbon energy source, while preserving the potential for natural gas to remain part of this energy solution.

- EEC initiatives generally have the effect of reducing throughput by promoting conservation and energy efficiency, but the customers that participate in the programs can reduce their energy consumption and therefore their overall energy bills. The ability to manage natural gas consumption makes the product itself more attractive.

Ultimately, by responding to customer demand and the changing policy and legislative environment, the New Initiatives help to promote natural gas as part of the energy mix in British Columbia and make efficient use of the natural gas infrastructure for the benefit of both natural gas customers and the Companies. In this sense, the Companies' interest in managing increased long term business risk through the New Initiatives is aligned with the interests of natural gas customers in having access to natural gas at lower rates and having access to new ways to meet their energy needs.

1.1.2 <u>Overview of the New Initiatives</u>

Each of the New Initiatives, when provided by the FEU, are regulated activities under the *UCA*. In the intervening years since the 2008 LTRP, the FEU have brought forward specific proposals under the provisions of the *Act* in respect of each of the four New Initiatives. As further described below, the Commission has granted various approvals, implicitly accepting that the New Initiatives are regulated. The decisions to date have, by and large, accepted that the New Initiatives can deliver benefits to existing and future ratepayers, the broader public, and also advance British Columbia's energy objectives.

Each of the New Initiatives is described in detail in subsequent sections of this Filing. The following is a high level overview of the New Initiatives, the regulatory processes that have occurred in respect of the New Initiatives, and the Commission's decisions regarding the New Initiatives.

BIOMETHANE UPGRADING

"Biogas" is a gas substantially composed of methane that is produced by the breakdown of organic matter (biomass) in the absence of oxygen. Although biogas in its raw form is combustible, it is not suitable for injection into the natural gas system. Technology exists that can upgrade raw biogas into "Biomethane", which is a gas that is safely interchangeable with natural gas and suitable for injection into a natural gas distribution system. The production and consumption of Biomethane out of biogas makes use of a renewable resource, and is considered carbon (or GHG) neutral because producing and consuming Biomethane does not add to the amount of carbon released into circulation.

FEI filed the Biomethane Application in 2010, which described a comprehensive business model for a Biomethane program. The Commission granted the necessary approvals to provide the FEU with a two-year period to launch the program, followed by a regulatory review of the program at the end of those two years. FEI has two supply projects approved (Salmon Arm and Catalyst), one of which is now operational, and residential customers have begun to enrol in the program. The Biomethane program falls within FEI's natural gas class of service and has its own rate schedules.

The Commission issued its decision in the Biomethane proceeding on December 14, 2010. The Commission's decision confirmed that the Biomethane Program is in alignment with British Columbia's energy objectives:

> *"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."* [8]

The two year period for the Biomethane program is still underway, and will conclude on December 14, 2012. At the conclusion of the period, as set out in the order and decision approving the program, FEI will file a post-implementation report regarding the program, and the Commission, FEI and interested stakeholders will have an opportunity to review the program in

---

8 Order No. G-194-10, dated December 14, 2010 (page 2), included in Appendix H.

further detail. The FEI have limited the Biomethane discussion in this Filing to the appropriate role of FEI in respect of owning and operating upgrading equipment, which was a matter left outstanding in the Biomethane Application and is the distinguishing feature of this offering from a regulatory perspective from the typical transmission and distribution functions performed by the FEU. Please refer to Section 4 for further evidence on this topic.

NATURAL GAS VEHICLES SERVICE

The CNG/LNG Service involves FEI owning and operating NGV fueling assets, and charging the customers (vehicle fleet owners) a rate that is based on the cost of service associated with those fueling assets. It is a separate service from the provision of the commodity to the fueling facility, which has its own rate schedules. Under this model, FEI installs, owns and maintains the necessary fueling facilities for a fleet of vehicles and enters into long-term “take-or-pay” contracts with the customer.

NGV Service is a natural extension of the Companies’ existing natural gas service offering to customers, involving bringing natural gas to customers in a usable form. The NGV service can provide several benefits. It benefits existing natural gas customers by adding cost-effective load, which increases throughput, and all else equal, lowers delivery rates for customers. It benefits NGV customers by providing operating cost savings, reduced fuel price volatility, and competitive advantages due to the associated environmental benefits. These reduced operating costs should, over time, translate to end use customers who make use of the services provided by the Companies making use of the NGV fleets. This outcome and reduced environmental footprint benefits the broader public. NGVs can employ made-in-B.C. technology and makes use of natural gas which is produced in BC.

FEI filed a comprehensive NGV Application in December 2010. The Commission issued its decision in the NGV proceeding on July 19, 2011. In the NGV Decision, the Commission considered the issue of whether NGV service provided by FEI is a regulated service for the purposes of the *Act*. The Commission determined that, unlike other market participants, if FEI provides NGV service, it is subject to regulation[9]. The Commission found that, with appropriate mechanisms in place to ensure that ratepayers are insulated from possible cost risks of the program, the benefits of the program justified its approval[10]. The Commission stated:

> *“The Panel is persuaded that benefits will accrue to FEI, FEI’s NGV customers, its ratepayers and the people of British Columbia if the NGV market can be kick-started. FEI’s NGV customers could potentially save a significant amount on their fuel costs and its ratepayers may enjoy some rate stability or even a reduction terms of delivery charges, other things being equal, if the load building that is forecast can be realized in the longer term. In addition, residents of the province will benefit from GHC reductions if diesel and gasoline vehicles switch to natural gas as a fuel. Further, a potential exists for*

[9] Order No. G-128-11, dated July 19, 2011 (page 18), included in Appendix H.
[10] The Commission’s approval is subject to FEI to filing amended General Terms and Conditions for the service to address concerns regarding cost recovery.

these GHG reductions to be monetized by FEI's NGV customers. Accordingly, the Panel finds the benefits outlined in this Application to be generally in the public interest." [11]

The Commission's recent decision on EEC for NGV ("NGV-EEC Decision") has introduced uncertainty regarding the availability of incentive funding for NGVs. However, the fundamental analysis summarized above remains valid. The FEU intend to explore ways to capture the benefits associated with CNG/LNG Service within the framework the Commission has laid out. NGV is discussed further in Section 5.

THERMAL ENERGY SYSTEMS

Thermal Energy Systems, or TES, are a variety of technologies that make use of renewable energy sources to provide space heating and cooling and hot water services. TES typically rely on conventional energy systems, such as natural gas boilers, to provide back-up energy and to meet peak demand. There are, generally speaking, three categories of TES:

(a) Geo-exchange systems[12] utilize the heat energy contained in near surface layers of the earth, ground water and surface water.

(b) Solar-thermal water heating systems, also called solar hybrid water heating systems, use solar collection tubes and piping to capture heat energy from the sun's rays and deliver it to a central heat exchanger, where it is converted to Domestic Hot Water ("DHW") and distributed in a manner similar to that described above for geo-exchange systems.

(c) District Energy Systems ("DES") employ a range of energy technologies and sources to deliver piped heating (hot water) and/or cooling (ambient or chilled water) to buildings and customers within a neighbourhood from a central plant location or locations.

The Commission has been regulating TES for some time for a variety of utilities and has approved GT&Cs to permit FEI to offer TES services as a class of service within the utility that is distinct from FEI's natural gas class of service. The Commission has also recognized that TES projects are in alignment with British Columbia's energy objectives. In the recent Corix UniverCity TES CPCN decision, the Commission stated:

"Section 2 of the CEA sets out British Columbia's energy objectives (listed in Appendix B). Those most relevant to this proceeding include (d), (g), (h), (i) and (j).

[11] Order No. G-128-11, dated July 19, 2011 (page 30), included in Appendix H.
[12] Also referred to as geo-thermal systems, earth exchange systems or ground and water source heat pumps.

> *CMUS notes that the NUS project is in alignment with many of these objectives and within the Application presents details of the GHG reductions which will result once the Biomass plant is implemented.*
>
> *The Commission Panel is in agreement with CMUS and notes that the project is in alignment with many of the most relevant objectives listed above. First, the type of technology being proposed by CMUS for this project is very innovative and is designed to support energy conservation and efficiency through the use of clean, renewable resources. As a consequence, the NUS, when fully operational will contribute to reaching BC GHG emission targets. Moreover, by relying on biomass for fuel the project clearly aligns with objectives (h), (i) and (j) by reducing waste and promoting the switch from natural gas heating to one with decreased GHG emissions on a community wide basis."*[13]

Developers, municipalities, school districts and others in BC now look to FEI to own and operate equipment that produces thermal energy at their sites using technologies that reduce energy consumption by both switching to the use of clean, renewable energy sources and more efficiently utilizing energy overall. This Filing discusses why TES presents a valuable service offering to customers, which is in the public interest. Appropriate cost allocation principles ensure that both natural gas and TES rates remain just and reasonable. Further information on TES is provided in Section 6 of this Filing.

ENERGY EFFICIENCY AND CONSERVATION

Since the 1990's, FEI and FEVI have been involved with Demand-side Management ("DSM") activities, to which the FEU refer as EEC. In general terms, EEC programs are DSM practices that influence how customers think about and consume energy. They are intended to help customers reduce energy costs through efficiency and conservation measures, and contribute to the creation of a "conservation culture" in BC. Under the FEU's EEC program, financial incentives are provided to customers who take qualifying efficiency and conservations steps. EEC funding is collected through the delivery rates paid by the FEU's natural gas customers, but customers who avail themselves of programs can reduce their overall energy bill, often reducing their carbon emissions in the process.

FEI and FEVI filed a comprehensive EEC Application in 2008, which established a new EEC framework. This included accepting a funding envelope, approving program areas, approving the portfolio approach to assessing the cost effectiveness of the EEC initiatives, establishing the test by which the portfolio is to be evaluated, and endorsing accountability mechanisms. The dispensing of EEC incentives to customers is based on the fact that customers must meet the qualifications as defined by the program to receive their incentive. The FEU sought and obtained additional EEC funding in the 2010-2011 RRA. The FEU have sought further funding for 2012-2013 as part of its Revenue Requirement Application that is before the Commission.

---

[13] Corix UniverCity CPCN, Decision, May 6, 2011, p. 30.

The 2008 EEC Application was for advance acceptance of EEC funding as a Section 44.2 expenditure schedule. In the Commission's decision approving the application, the Commission held that the design of the residential and commercial energy efficiency programs was "reasonable, flexible and in the public interest"[14].

The issue that has been raised by the Complaints (further discussed below) relates specifically to how EEC funds are dispensed. Accordingly, this issue is the focus of Section 7 of this Filing. The Filing describes how the FEU dispense EEC funds based on the principle of universal access by customers, and explains why that approach remains appropriate even in the context where the incentives are paid to promote thermal energy projects.

1.1.3 The Nature of the Inquiry and the FEU's Proposed Guidelines

In the 2010 LTRP Decision, the Commission expressed a desire to have a comprehensive review of the issues raised in the applications that have been brought forward to advance the New Initiatives[15]. On July 8, 2011, the Commission issued the Scoping Order in this Inquiry. The Scoping Order set out the scope and issues for this Inquiry, and invited the FEU and other parties to file evidence in response to the issues identified by the Commission. The Commission's order specifically directed that the Inquiry is not a means of re-opening past decisions of the Commission or to impinge on any regulatory processes currently underway. Rather:

> *"It is a forward looking assessment with the aim to establish principles that can be applied to future regulatory processes in the area of AES and other new initiatives."*[16]

In response to the Commission's Scoping Order, the FEU are providing this Filing which contains evidence regarding the FEU's activities in relation to the New Initiatives, and proposed standards and guidelines in response to the specific issues identified by the Commission in Appendix A to the Scoping Order.

As set out above, and as further explained in Sections 4, 5, 6, and 7 of this Filing, the Commission has already considered and decided many of the significant regulatory issues surrounding the New Initiatives. In particular:

(d) The Commission has previously found that the FEU's Biomethane, NGV, and TES[17] service offerings are regulated public utility services.

---

14 Order No. G-36-09, dated April 16, 2009 (page 13), included in Appendix H.
15 Order No. G-14-11, February 1, 2011, (page 28), included in Appendix H.
16 Order No G-118-11, Appendix B.
17 In respect of AES, while the FEU have not filed a CPCN or related approval for an AES project, the Commission did approve the NSA which contained a rate schedule for AES services, and has also approved CPCN applications for AES projects for other public utilities such as Corix and Dockside Green LLP.

(e) The Commission has previously found that the Biomethane Service 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 with the program on a pilot basis.

(f) The Commission has previously found that benefits will accrue to FEI, FEI's NGV customers, its ratepayers and the people of British Columbia if the NGV market can be kick-started, and that the program is aligned with British Columbia's energy objectives.

(g) The Commission has previously found that certain TES projects are in alignment with British Columbia's energy objectives.

(h) The Commission has previously identified that EEC is in the public interest.

The FEU's proposed guidelines reflect these prior determinations and others, which the Commission has directed should not be revisited in this Inquiry.

The FEU note that these prior decisions and findings, and the proposed guidelines that reflect them, do not predetermine whether or not projects going forward are in the public interest. Rather, they are intended to acknowledge that, based on previous decisions, the determination of the public interest in particular instances will normally turn on other considerations, primarily cost allocation and rate design, rather than on whether or not they support provincial policy objectives or benefit the broader public, for example. Adopting these principles as an outcome of this Inquiry will avoid the need for the FEU to re-file extensive policy evidence in each future proceeding relating to the New Initiatives. The outcome will be a more focussed public interest examination of proposed projects and expenditures and ultimately, more efficient Commission processes, which is in the interests of all concerned.

1.2 THE ESAC AND CORIX COMPLAINTS

As the Commission is aware, this Inquiry was triggered by a complaint filed by the Energy Services Association of Canada ("ESAC") on April 27, 2011. ESAC's complaint specifically identified the following concerns:

(a) previous public consultation by the FEU in relation to the 2010 LTRP;

(b) the use and distribution of EEC funding by the FEU;

(c) the role of a "regulated utility" by the FEU in the delivery of these services and the potential cross-subsidization of AES (TES) activities by natural gas rate payers; and

(d) use of sensitive market information within the FEU.

The FEU's evidence addresses items (b) through (d), as each of those items was included within the scope of the Inquiry as set out in the Commission's Scoping Order. The FEU continue to take strong exception to the complaint and statements of ESAC in their letter regarding previous consultation, but have not addressed this issue in a comprehensive way as the Commission made clear in its order that this is to be a forward looking Inquiry, and this issue was not included within the scope of the Inquiry as defined in Appendix A of the Scoping Order. The FEU will speak to this issue should ESAC raise it again in his proceeding.

The FEU believe that most of the items identified in the letter from Corix Multi Utility Services Inc. ("Corix") to the Commission dated May 25, 2011, were included within the scope of this Inquiry, and to the extent that they were, the FEU have provided responsive information in this Filing.

1.3 FUTURE LTRPS

In the Commission's 2010 LTRP Decision, the Commission identified areas in which the FEU could improve future LTRPs, including a number of directives relating to reporting on matters that relate to the New Initiatives. The FEU wish to make clear that they fully intend to address these issues in future LTRPs, as directed by the Commission, and have not attempted to address these issues in this Filing. The FEU anticipate that they will file their next LTRP in 2013.

1.4 ORGANIZATION OF THE EVIDENCE

The remaining sections of this Filing are organized as follows:

- Section 2 describes the customer, policy and business drivers for the New Initiatives.
- Section 3 describes the legal framework within which the New Initiatives are reviewed and regulated under the *Act*.
- Section 4 describes FEI's Biomethane Service, with a particular emphasis on the FEU's ownership and operation of upgrading equipment.
- Section 5 describes FEI's NGV Service.
- Section 6 describes FEI's TES, and deals with a variety of topics regarding the nature of regulation, and public interest considerations.
- Section 7 describes FEI and FEVI's EEC program, and explains in particular how EEC funds are dispensed to customers regardless of what energy services provider the customer chooses to partner with.

- Section 8 sets out the FEU's proposed standards and guidelines in response to the Commission's scope and issues as described in Appendix A of the Scoping Order.

There are a variety of materials from other applications, research, expert reports, and past decisions appended to the Filing. The FEU considered that it would be useful in the context of this proceeding to consolidate the available information on the New Initiatives in one place. The FEU have explained and referenced those appendices in the context of the Filing itself.

2 DRIVERS FOR NEW INITIATIVES

The energy environment in BC has seen significant changes in the last decade or so. The changes have included trends in natural gas competitiveness vis a vis other energy sources, BC's evolving provincial energy and environmental policies, changing customer expectations, economic realities and more. Overall, these developments present increasing challenges to the FEU's traditional natural gas business, but also present an opportunity for the provision of other energy solutions within the utilities to our existing and new customers. The FEU's pursuit of the New Initiatives, initially identified in the FEU's 2008 LTRP, is a step toward trying to adapt to this changing energy environment for the benefit of our existing natural gas customers. The FEU continue to believe that natural gas has a significant role to play in meeting BC's energy requirements today and into the future because of its inherent physical properties, such as having the lowest emissions of the fossil fuels, no/low particulate matter, flexibility in end use applications, but not all customers or stakeholders share the same view as the FEU. This makes for challenging times for the FEU to maintain our natural gas throughput in our traditional market segments, which is in the interests of customers and the shareholder alike.

This Section is organized as follows:

- Section 2.1 describes how the FEU's New Initiatives respond to the declining throughput levels that impact customer delivery rates. This decline in throughput levels is mainly due to declining annual use rates from existing customers and, recently, the declining rate of capture of the new construction market, particularly in the multi-family sector;

- Section 2.2 outlines how the FEU's New Initiatives align with government energy policy and "British Columbia's energy objectives", which are focused on reducing GHG emissions in the Province;

- Section 2.3 discusses how the energy environment in BC is unique when compared to other jurisdictions and how the FEU's New Initiatives respond to the challenges in BC's energy environment in providing energy solutions to reduce GHG emissions in the Province;

- Section 2.4 provides an overview of how the FEU's New Initiatives respond to customer expectations and demand for "greener alternatives"; and

- Section 2.5 summarizes why the FEU are in the best position to offer New Initiatives and how New Initiatives address the changing energy environment.

The FEU have included in Appendix A related excerpts of materials filed in prior proceedings including the 2008 and 2010 Long Term Resource Plans, as well as 2010-2011 RRA. These materials provide additional background information on the drivers discussed in this Section.

2.1 RESPONSE TO DECLINING THROUGHPUT LEVELS THAT IMPACT RATES

The FEU have been experiencing lower throughput levels over the last decade, which has negative consequences for the customers of the FEU. Delivery costs are recovered from customers based on taking the total system costs and dividing them by the amount of throughput. Therefore, all else equal, if throughput levels decline, rates to customers increase.

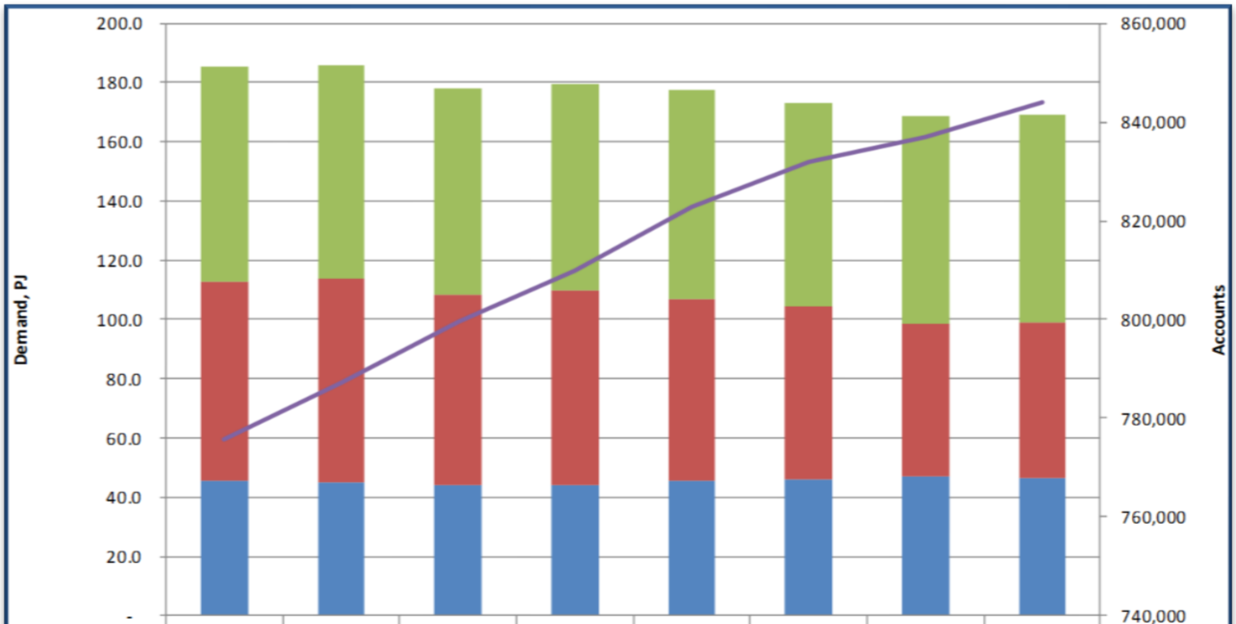
The results from 2010 Residential New Home Survey (“RNHS”) indicate that over the last four years the FEU has experienced a significant loss of hot water and space heating load in the new construction market along with declines in market share. This is of concern to the FEU as fewer customer attachments and lower gas consumption associated with new customer attachments that use natural gas for end uses such as fireplaces and cook tops, but electricity for hot water and space heating needs, directly affects our customers. Space and water heating represents the largest household energy usage, equating to approximately 80 percent of household energy use. The loss of such loads on our system leads to upward rate pressure for the remaining customers. The FEU must recover that loss of revenue through delivery rates over time from its customers. Based on the historical evidence presented in the 2010 RNHS study results, the FEU expect a continuing trend of declining natural gas load.

The FEU discuss below the role of the New Initiatives in responding to the upward pressure on delivery rates. Three of the New Initiatives - in particular the Biomethane Service, CNG/LNG Service and Thermal Energy Services - can help offset or reduce the impact of lost throughput on the natural gas system, thereby benefiting existing and new customers in the long term. EEC programs are a tool for customers to manage energy costs by reducing their energy consumption through efficiency and conservation. The common theme to the New Initiatives is that they all impact the natural gas infrastructure in some way, while providing “greener” energy solutions to the customer.

2.1.1 Overview of Declining Throughput

As demonstrated in Figure 2-1 below, the FEU have experienced declining throughput levels in the last decade.

Figure 2-1: Mainland Normalized Demand vs. Accounts



	2003	2004	2005	2006	2007	2008	2009	2010
Residential	72.6	72.0	69.3	70.0	70.6	68.8	70.0	70.0
Industrial	67.4	68.6	64.6	65.5	61.4	58.6	51.3	52.4
Commercial	45.3	45.2	43.9	44.1	45.5	45.9	47.2	46.6
Accounts	775,603	787,123	799,427	809,718	822,687	831,886	836,976	843,845

Since 2003, FEI has added an average of approximately 9,000 net new customers per year, for a total increase in accounts of just over 68,000. In the same time period, FEI has witnessed a decline in residential and industrial total demand, while commercial total demand has remained relatively flat. As a result, the total demand for the Mainland region is now 16 PJs less than demand in 2003.

It should be highlighted that the number of customer accounts reflected in Figure 2-1 above (843,845 in 2010 for FEI) should not be equated with the number of *people* served by the natural gas systems[18]. For example, in 2011 the single family residential customer count is

---

[18] The Commission appears to have equated the two in the recent NGV-EEC Incentive Review Decision (Order G-145-11), at page 13, included in Appendix H, where it indicated that:

> *However, it is also relevant that FortisBC Energy Inc. had approximately 830,000 customers at the time of its RRA in 2009. (Exhibit A2-4, Terasen Gas Inc. 2010-2011 Revenue Requirements Application, p. 1) FortisBC Energy (Vancouver Island) Inc. added a further approximately 100,000 customers. It is questionable whether this small customer base should fund initiatives which benefit a few select large potential customers engaged in the transportation sector, as well as all British Columbians generally through the reduction in GHG emissions. It is arguable that the funds collected from ratepayers could provide more direct benefits to those ratepayers by being used in conventional demand-side management programs which may allow those ratepayers to reduce their own consumption and, hence, their bills and which would also have the additional outcome of reducing GHGs.*

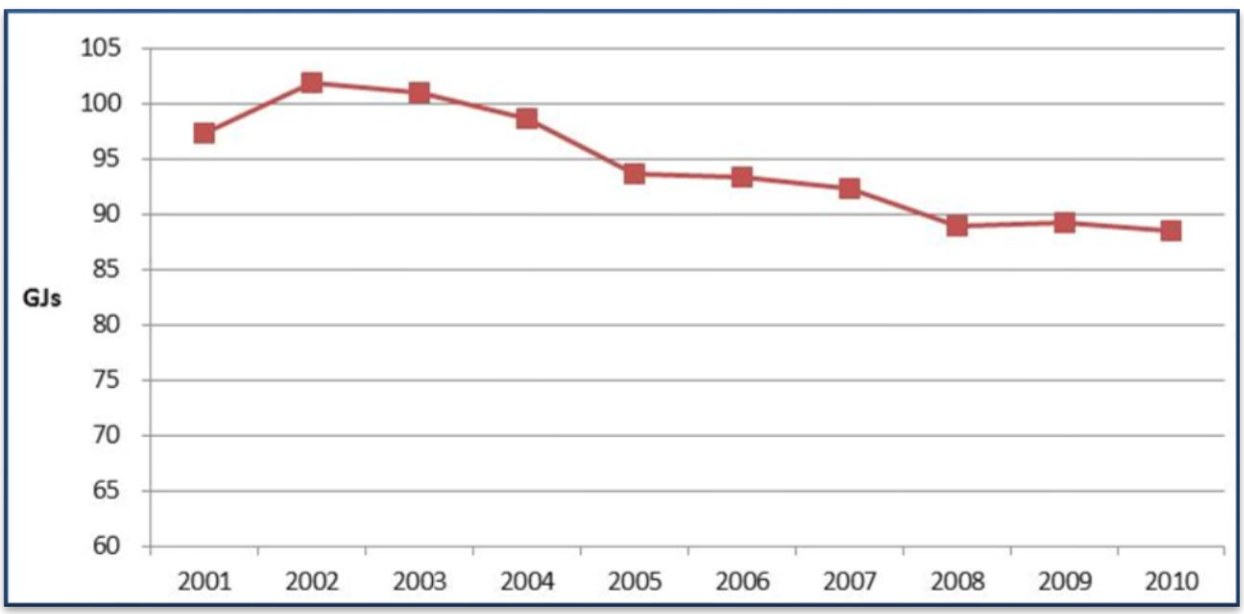
expected to reach 864,000 for all regions. At 2.5 people per household[19], the total population served by the FEU is estimated to be approximately 2.16 million. The latest BC population figure is just over 4.5 million[20], implying that at least 47 percent of the population is served by the FEU. This figure is understated because it does not include multi-family customers that are served by a single meter, whose consumption appears in other rate classes. Further, the FEU provide natural gas service to municipal and provincial government, hospitals, schools, and such. The services of these organizations are provided to all BC residents, which means that all British Columbians are directly or indirectly impacted by our rates overtime. It should be noted that consumption of natural gas and electricity in the Province are approximately equal, each representing about 20 percent of annual energy consumed[21].

Throughput levels have been negatively affected by two trends: 1) declining annual use rates from existing customers and 2) declining rate of capture of the new construction market. These trends have led to lower throughput levels and increased the pressure on customer rates. Each of these trends is further discussed below.

2.1.2 Declining Use Per Customer

Residential use rates (average consumption per household) for the FEU have been declining during the past ten years. Figure 2-2 below demonstrates that there is a clear and consistent downward trend in Use per Customer ("UPC") and UPC for this sector is expected to decline in the years to come.

Figure 2-2: The FEU's Consolidated Residential Use Per Customer (Normalized)



[19] Statistics Canada: Average Number of Persons per Private Household (2006).
[20] BC Stats: BC Quarterly Population, 1951-2011.
[21] See the excerpt from the 2008 Resource Plan, included in Appendix A.

The decline in UPC rates has been attributed to a variety of factors. While not a comprehensive list, the main drivers of this continuing decline include the retrofit of older, less efficient appliances with new high efficiency units, and also upgrades to insulation, window, doors, and building shells.

Although efficiency improvements are driven by a number of factors such as technological advances, natural gas prices, public policies/programs and the state of the economy, they are also influenced by FEI and FEVI's EEC programs[22]. Since the Companies recently received approval for EEC programs that have significantly greater levels of funding, it is reasonable to assume that these cost effective programs will impact the average UPC over time. In 2010 the impact was estimated to be a 0.12 Gigajoule ("GJ") decline in Residential average UPC. In 2011, the impact is forecast to be a 0.16 GJ decline in Residential average UPC. While EEC savings are not a direct input into the forecast model, their effect is implicit in the generally declining UPC trends.

Other factors that will impact UPC over time are changes in government regulations and building codes that impact the efficiency of gas end-use appliances installed in new construction; the increasing proportion of townhouses and row housing in new construction (discussed the Section below); the introduction of new energy forms and technology to replace natural gas in its traditional application (space and water heating); and consumer demand response to perception of natural gas as an unclean fossil fuel since the addition of carbon tax in BC (further discussed in Sections 2.2 and 2.3).

As shown in Figures 2-3, 2-4 and 2-5, in the Mainland region, a decline in Commercial Rate Schedule 23 is offset by an increase in Commercial Rate Schedule 2 UPC, resulting in a slight increase in demand in the Mainland region. In addition, decreases in large commercial use rates in the Vancouver Island region and Whistler region result in the decrease in commercial demand shown in Figure 2-6 below.

[22] EEC Programs are currently only available in the Mainland and Vancouver Island regions, and not Whistler or the Fort Nelson service areas.

Figure 2-3: Mainland Consolidated Rate Schedule 2 Use Per Customer

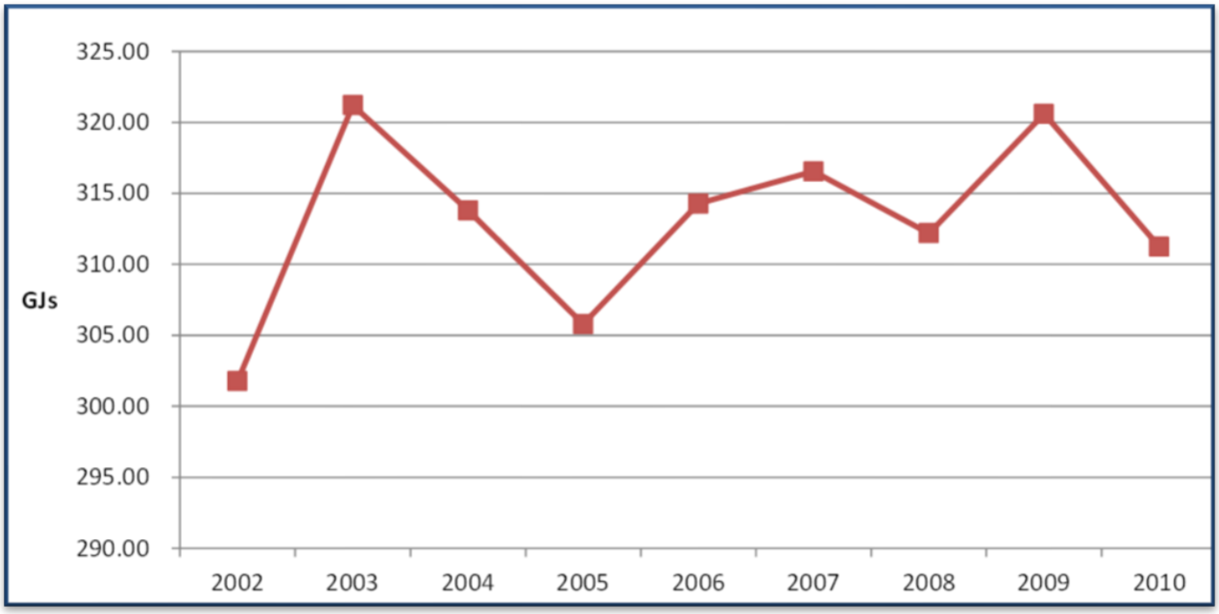


Figure 2-4: Mainland Consolidated Rate Schedule 3 Use Per Customer

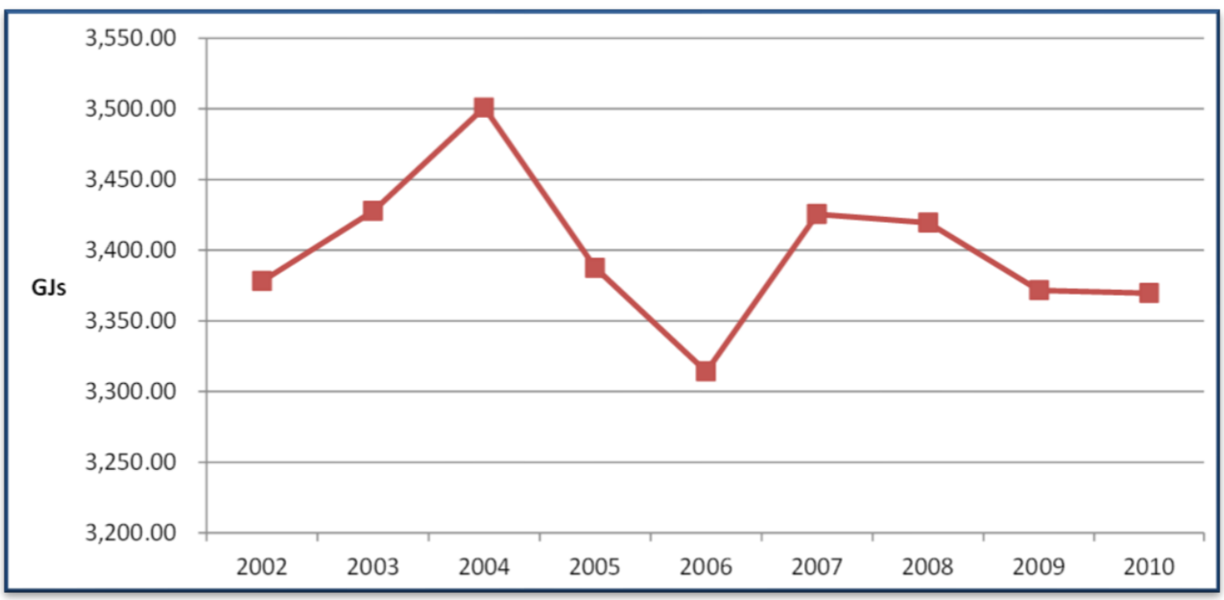


Figure 2-5: Mainland Consolidated Rate Schedule 23 Use Per Customer

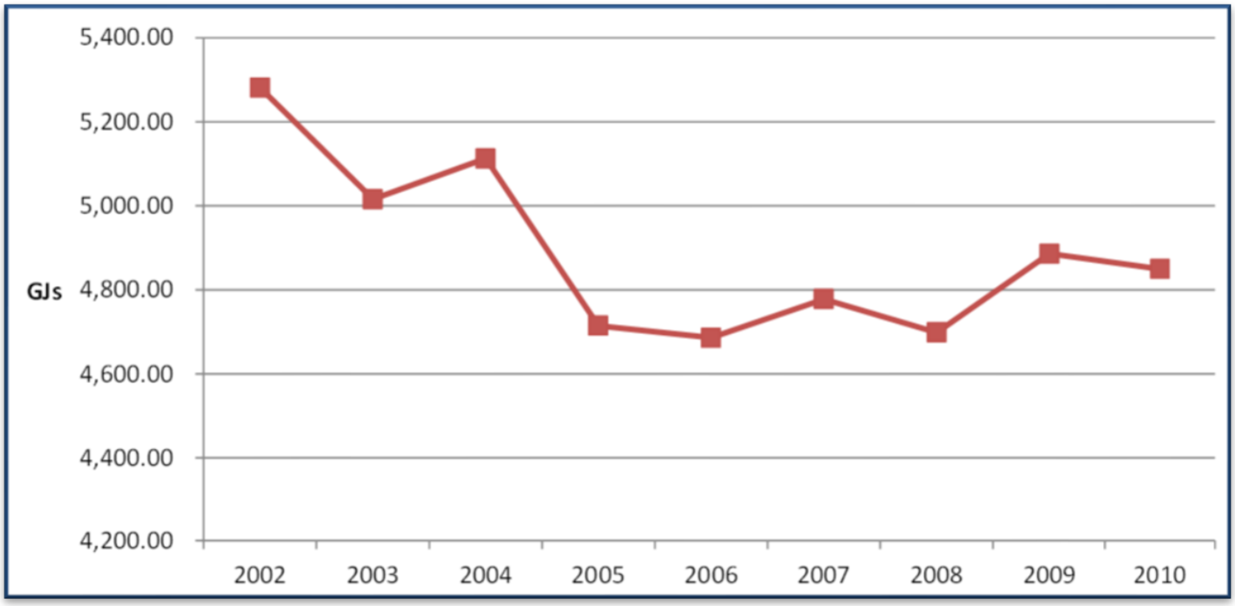
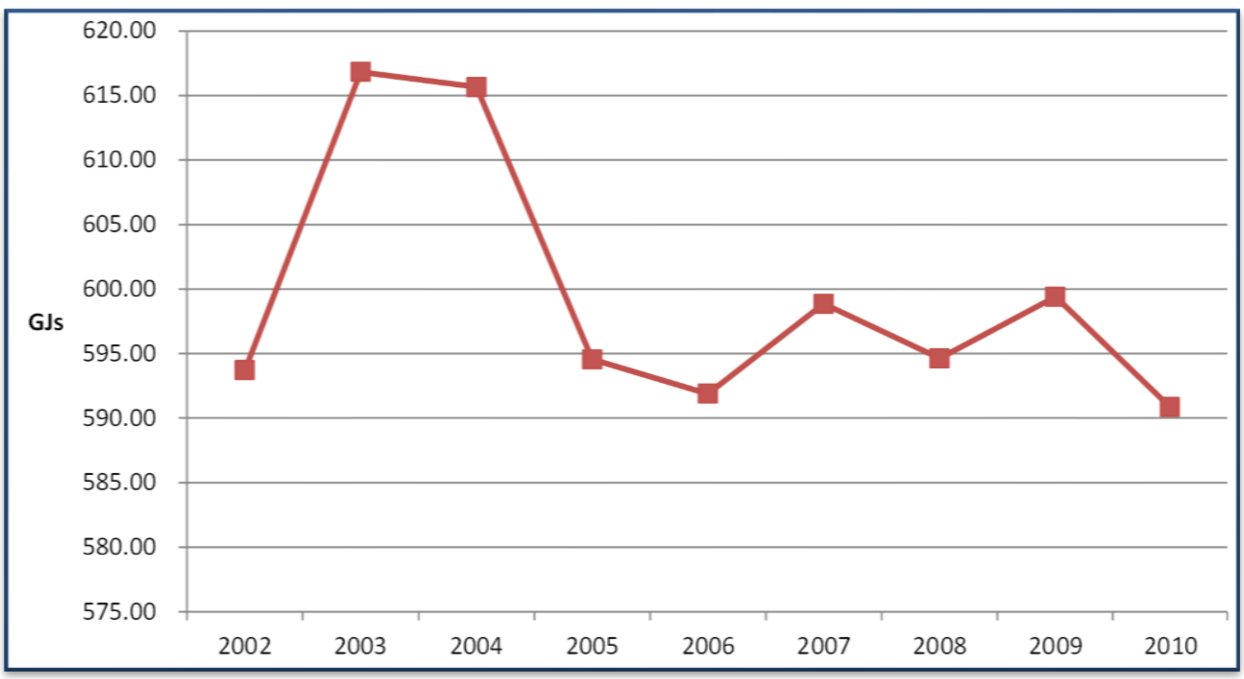


Figure 2-6: The FEU's Consolidated Commercial Use Per Customer



The use of alternative energy versus conventional energy systems may have significant impact on both energy savings and GHG emissions in these commercial rate classes in the future. Renewable thermal energy solutions can cost-effectively improve energy efficiency and reduce GHG emissions. To better understand the impact of new initiatives on conventional energy demand and GHG emissions, the FEU modelled a 10-year demand scenario in which 185 100-

unit condominium buildings in the Lower Mainland were used to model building heating and cooling demand growth over time[23]. The energy use and GHG emissions for the application of conventional energy systems (electricity for space heating/cooling and natural gas for water heating and make-up air) were then compared to the application of alternative renewable systems.

A wide variation of integrated energy systems is possible. The FEU have modelled this scenario using a typical geo-exchange system that would serve approximately 70 percent of the buildings' thermal energy requirements. In this scenario the number of integrated energy systems implemented in the initial years is low, but the growth rate is high with the number of systems implemented doubling through the first 4 years. Beyond 4 years, growth occurs at a slower pace, resulting in a total of 185 systems at the end of the 10 year period. The inputs into the demand curve are based on a per-customer or per-unit basis and then extrapolated for the total number of customers.

The model revealed that implementation of renewable thermal energy systems resulted in a total annual energy savings of 362,094 GJ of natural gas and 38 GWh of electricity by the year 2020 for the 185 buildings over the ten years. Cumulative natural gas and electricity savings over the ten year period are approximately 1,880,000 GJ and 199 GWh respectively; cumulative GHG emissions savings is approximately 100,304 tonnes of CO_2e over ten years, which represents a 68 percent reduction from the baseline emission scenario. Using this model as an example, renewable thermal energy solutions may have a significant impact on declining use per customer rates on the commercial sector.

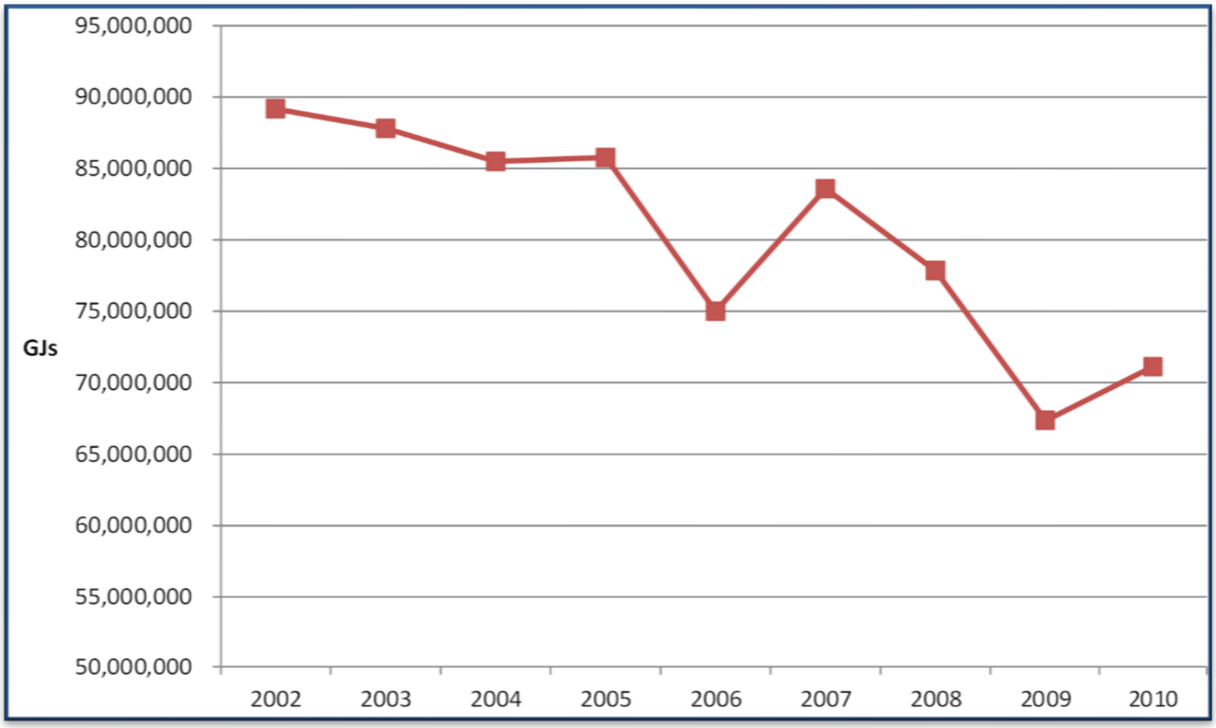
Given this scenario, it is possible that the commercial sector as a whole could see declining total throughput as new buildings make use of these technologies and energy forms overtime; even though the commercial sector as a whole has not contributed to the 16 PJ in total throughput over the last decade or so.

Furthermore, as seen in Figure 2-7 below the demand from the Industrial rate classes is forecast to stabilize above 2010 levels at just under 75 PJs. This is an increase over the 67.5 PJs delivered in 2009 but well below the volumes delivered prior to 2005.

---

[23] For study assumptions, please refer to 2010 Long Term Resource Plan (p. 100 – 102, Appendix B-6 and Appendix B-7), included in Appendix A to this Submission.

Figure 2-7: The FEU's Consolidated Industrial Demand

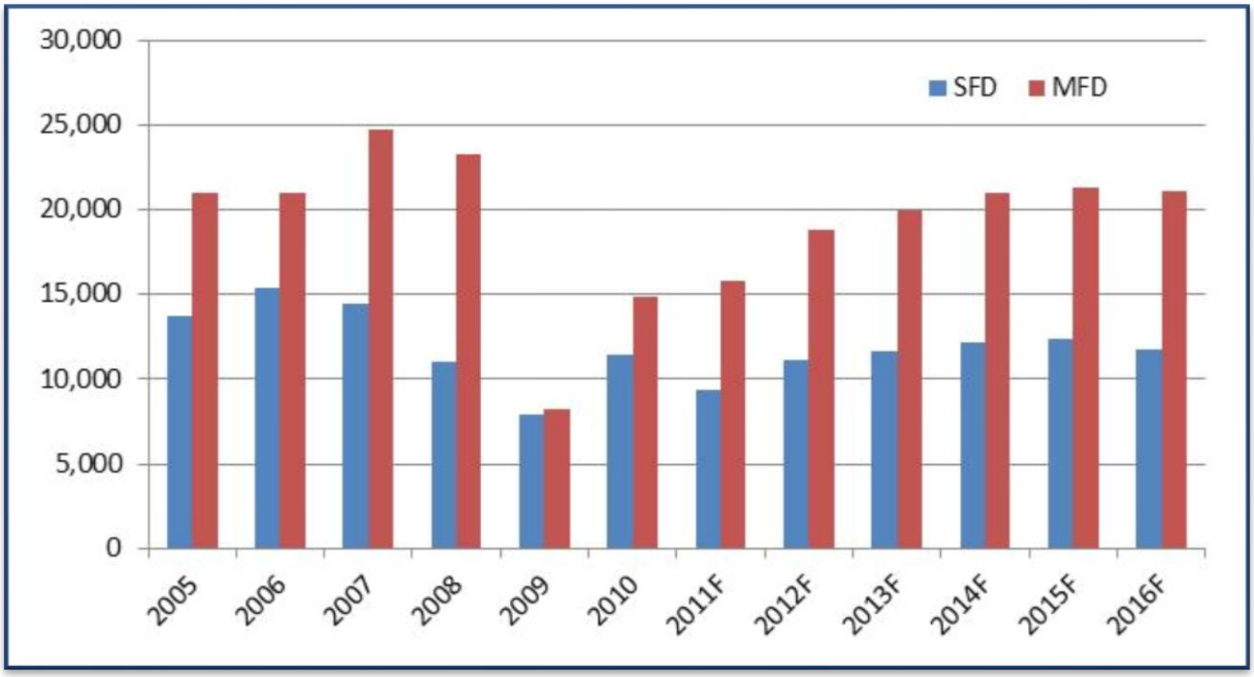


2.1.3 Declining Capture Rates

A second factor that compounds the declining use per customer is the lower capture rate for new building stock.

With housing affordability challenged in the Lower Mainland, a greater proportion of new housing in recent years has been and will continue to be multi-family dwellings ("MFD") (see Figure 2-8 below) that historically have been primarily electrically heated.

Figure 2-8: BC Housing Starts



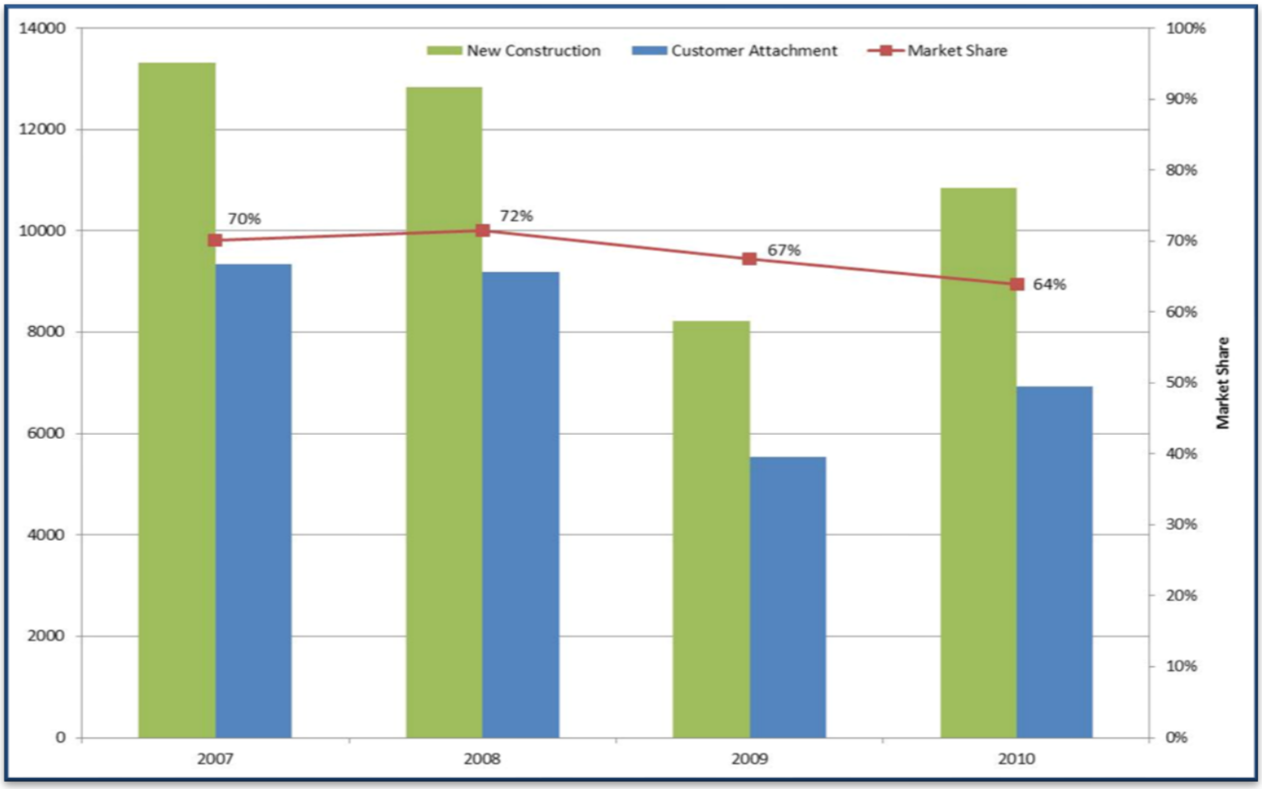
Additionally, new customers typically have smaller loads than our average residential customers, as they use natural gas for appliances such as cook tops, barbeques and decorative fireplaces, as opposed to space and water heating. The impact of declining capture rates is significant, particularly when new customer additions with space and water heating as the core load are important for offsetting the declining use per account of the FEU's existing customer base.

2.1.3.1 Natural Gas for Space Heating

The FEU recently conducted an analysis of natural gas customers added to the system between 2007 and 2010[24]. Figure 2-9 illustrates the results of this analysis and demonstrates that the market share (proportion of new homes captured by natural gas for space and water heating) is in a state of decline. The market share of natural gas in new home construction has dropped from 72 percent to 64 percent from 2008 to 2010 indicating that builders and developers, who are major influencers in most of the new construction, are moving away from natural gas to other fuels, primarily electricity.

[24] The finalized 2010 RNHS will be available in Fall 2011.

Figure 2-9: Market Share of Natural Gas



Source: FortisBC from BC Assessment New Construction

Further, Table 2-1 below summarizes the main space heating fuels for natural gas homes (as characterized by those homes with natural gas service) by vintage of dwelling. The data shows a decline in the proportion of new homes (SFD, Town/Row House and Duplex/Triplex) constructed between 1996 and 2005 that use natural gas as the main space heating fuel. Prior to 1996, roughly 91 percent to 93 percent of gas serviced homes were using natural gas as the main space heating fuel. This percentage declined modestly to 87 percent for homes built between 1996 and 2005, and has declined much more rapidly to 73 percent for homes built since 2005.

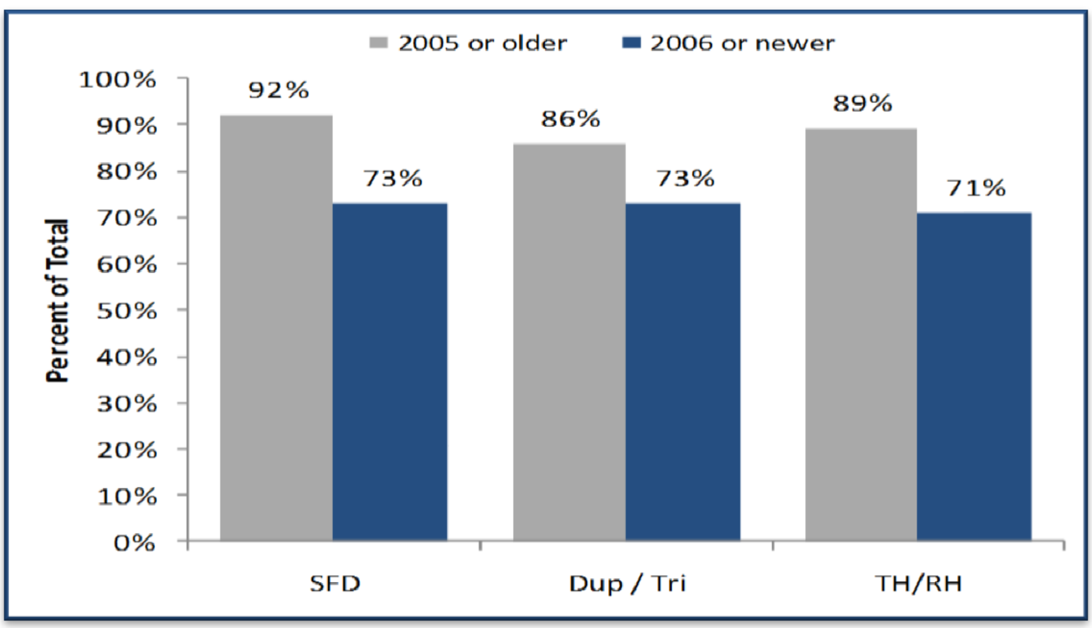
Table 2-1: Main Space Heating Fuel by Dwelling Vintage (%)

Main Space Heating Fuel	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or newer
Electricity	7.0	5.0	7.0	7.1	9.9	21.5
Natural gas	**91.2**	**93.7**	**90.8**	**91.4**	**87.3**	**72.6**
Piped propane	0.2	0.8	0.2	0.2	0.4	0.2
Bottled propane	--	--	0.3	--	--	0.1
Oil	0.3	0.2	0.1	--	0.1	0.1
Wood	1.4	0.3	1.3	1.2	0.3	0.5
Geothermal	--	--	0.3	--	0.5	3.8
Other	0.0	--	--	0.0	1.4	0.8
DK	7.0	5.0	7.0	7.1	9.9	0.3

Source: Residential New Construction Research, Sampson Research Inc., 2010

Figure 2-10 below compares natural gas shares by dwelling type for the stock of gas homes constructed prior to 2006 (from the Residential End Use Survey ("REUS")) and new homes constructed since 2005 (from the 2010 RNHS). The figure shows the decline in natural gas as a main space heating fuel for new gas homes across all three dwelling types (single family detached; duplexes and triplexes; and townhouses and row houses).

Figure 2-10: Gas Share of Main Space Heating Fuel



Source: Residential New Construction Research, Sampson Research Inc., 2010

2.1.3.2 Natural Gas for Domestic Hot Water

The use of natural gas or piped propane for Domestic Hot Water ("DHW") (also referred to as "Domestic Water Heating" ("DWH")) in new gas homes has declined significantly compared to the stock of gas homes built prior to 2006. Table 2-2 below from the 2010 RNHS shows that 69 percent of gas homes built since 2005 had a domestic hot water heater in the dwelling that used gas, compared to 91 percent of gas homes built prior to 2006. Electric hot water heaters increased their share in gas homes from 12 percent prior to 2006 to 35 percent in new gas homes. Natural gas DHW share among new homes is highest in the Lower Mainland (76 percent of homes with a DHW heater) and lowest on Vancouver Island (49 percent).

Table 2-2: Domestic Hot Water Fuels by Region (%)

DWH Fuel	Lower Mainland	Vancouver Island	South Interior	North Interior	2010 RNHS	2008 REUS
Electricity	27.4	55.9	41.7	32.2	34.7	11.6
Natural gas	**76.1**	**49.0**	**59.1**	**70.8**	**68.7**	**90.9**
Piped propane	--	0.1	0.7	--	0.1	0.2
Bottled propane	--	0.4	--	1.2	0.2	--
Oil	--	0.4	--	--	0.1	0.2
Geothermal	--	0.4	2.6	0.6	0.4	--
No DWH Indicated	7.6	4.9	6.0	4.9	6.7	6.9

Source: Residential New Construction Research, Sampson Research Inc., 2010

When analyzed by dwelling vintage (as shown in Table 2-3 below), the data shows that the use of gas for DHW has markedly declined in new homes built since 2005. For example, 79 percent of gas homes built before 1950 have gas DHW, compared to 91 percent of gas homes built during the 1996 to 2005 period. This trend reversed dramatically, however, in homes built since 2005, with gas DHW present in only 69 percent of the units. The shift for new homes has been from gas to electric DHW, with electricity now accounting for 34 percent of DHW in new gas homes, compared to between 6 percent and 14 percent of older homes, depending upon the vintage. Builders and developers surveyed in the 2010 RNHS study have attributed the decline of gas water heating to regulatory developments for gas furnaces such as the requirement to install more costly high efficiency units, the loss of interior space to accommodate venting, and the relative cost disadvantage of installing a gas water heater as opposed to an electric water heater.

Table 2-3: Domestic Hot Water Fuels by Dwelling Vintage (%)

DWH Fuel	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or newer
Electricity	14.2	10.5	12.4	11.9	6.1	34.7
Natural gas	**79.2**	**86.2**	**83.1**	**88.8**	**91.1**	**68.7**
Piped propane	--	0.0*	0.2	0.2	0.3	0.1
Bottled propane	--	--	--	--	--	0.2
Oil	1.8	0.1	--	0.0*	--	0.1
Geothermal	--	--	--	--	--	0.4
No DWH Indicated	6.9	3.0	4.4	4.5	5.0	6.7

Source: Residential New Construction Research, Sampson Research Inc., 2010

2.1.3.3 Natural Gas for Space Heating and Domestic Hot Water

Additional data confirms that there has been a significant reduction in the number of new homes using gas for DHW. Table 2-4 below summarizes the incidence of homes with gas furnaces or boilers paired with gas DHW or electric DHW, by the three dwelling types[25]. For example, 56 percent of new SFDs have the traditional pairing of gas space heat and gas DHW, compared to 81 percent for the stock of older gas SFDs, a decline of 25 percentage points. Seventy-three (73) percent of townhouses/row houses built prior to 2006 have gas space heat (gas furnace or boiler) and gas DHW, compared to 54 percent of townhouses/row houses constructed since 2005.

Table 2-4: Gas Space Heat and DHW Combinations by Region and Dwelling Type (%)

	Lower Mainland	Vancouver Island	South Interior	North Interior	RNHS 2010	REUS 2008
Single Family Detached						
Gas space heat & gas DWH	68.1	19.5	46.0	64.3	56.2	81.2
Gas space heat & electric DWH	20.6	6.9	35.7	30.7	21.0	10.8
Duplex / Triplex						
Gas space heat & gas DWH	51.8	18.3	78.6	67.7	54.6	77.3
Gas space heat & electric DWH	22.2	40.0	14.3	20.6	23.4	11.6
Townhouse / Row House						
Gas space heat & gas DWH	54.9	40.7	62.5	57.9	53.9	72.8
Gas space heat & electric DWH	16.7	29.6	31.3	36.8	21.5	12.1
All Dwellings						
Gas space heat & gas DWH	65.1	22.2	50.3	63.6	55.7	78.7
Gas space heat & electric DWH	19.9	11.2	33.7	31.0	21.2	11.9

Source: Residential New Construction Research, Sampson Research Inc., 2010

25 These homes may have other gas end-uses. However, this analysis concentrates on the largest gas loads which traditionally have been space and domestic water heating.

Figure 2-11 below illustrates the incidence of gas space heating paired with gas DHW for the three dwelling types, by dwelling vintage. The data for SFDs confirm that the trend away from having gas DHW is a recent development. Data for duplexes / triplexes, and townhouses / row houses suggest the decline began in homes constructed in the 1996 to 2005 period, and became significantly more pronounced in homes built since that time.

Figure 2-11: Homes with Gas Space Heating and Gas DHW

Source: Residential New Construction Research, Sampson Research Inc., 2010

The likely implication of this trend towards declining use rates and declining capture rates is that people are now adopting electricity for heating and cooling at a faster rate than before. From an overall BC energy use perspective, as this trend continues the electric systems serving British Columbians will face increasing pressure to make investments in the necessary generation and transmission infrastructure to meet growing demands for capacity at the winter system peak (which is driven by residential heating demand).

From the perspective of gas customers, as declining use rates from existing customers and a declining capture rate of the new construction market reduce natural gas throughput levels, FEI faces an on-going challenge to maintain throughput levels at existing levels. New government regulation and building codes, a changing mix of building type in new construction and new technologies and energy forms are increasing risk to the FEU's core gas offering, and are driving the FEU to search for new ways to make efficient use of the existing natural gas infrastructure for the benefit of customers.

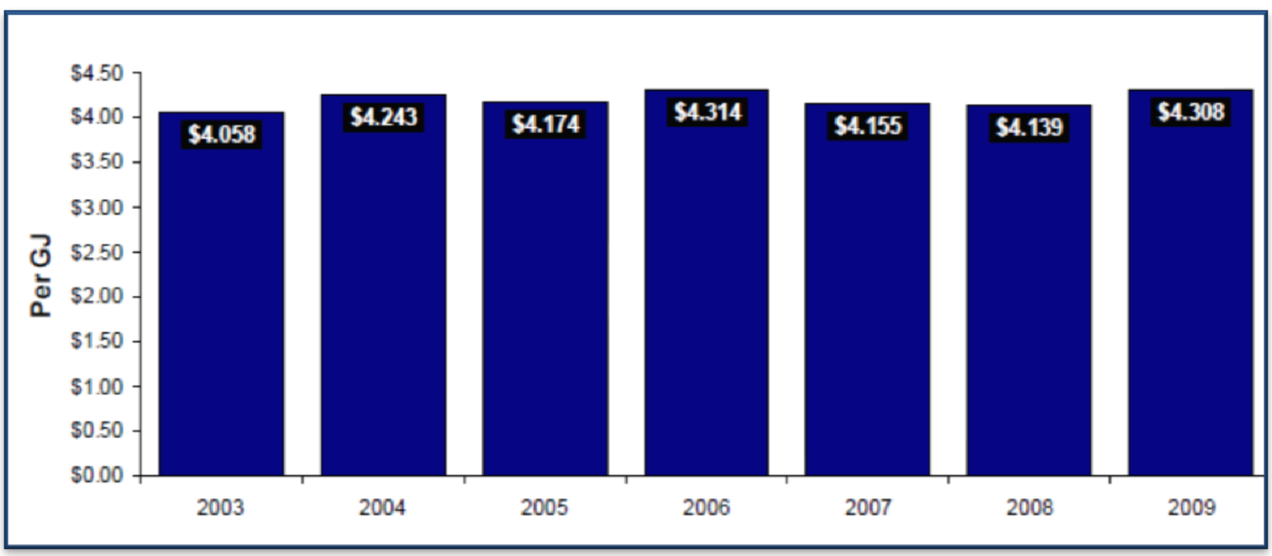
2.1.4 Impact of Declining Throughput on Revenue and Rates

As discussed previously, this loss of space and water heating load is of great concern, as the FEU must recover lost revenue through future delivery rates for its existing customer base. This is based on the fact that much of the utility cost of service is fixed in nature and therefore substantially the same level of costs must be recovered over a smaller throughput volume. As an example of how lost throughput can affect customer rates, independent research regarding new residential construction indicates that 35 percent of new gas homes built from 2006 to 2010 have gas for end uses such as cook tops and BBQs, but not for space & water heating[26]. This equates to roughly 20,100 homes and 1,570,000 lost GJs assuming 78 GJ per household[27] for space & water heating on a normalized year basis. Multiplying the quantity of lost load by our average delivery rate leads to a conservative estimate of approximately $5.1 million in lost revenue from 2006 to 2010 that the FEU will have to recover through rates from all the customers.

2.1.5 Our Commitment to Cost Effective Delivery Service Despite Declining Throughput Levels

As discussed earlier in this Section, reduction in natural gas demand, all things being equal, increases delivery rates. As Figure 2-12 demonstrates, however, the FEU have been able to ensure that the Lower Mainland delivery rates remained stable (in nominal dollars) over the multi-year Performance Based Ratemaking ("PBR") settlement agreement period (2003-2009). This pattern was also seen in other rate classes and service areas.

Figure 2-12: Stable Effective Lower Mainland Residential Customer Delivery Rates 2003-2009



26 Based on Residential New Construction Research Analysis and Highlights, Sampson Research Inc., 2011.
27 Conditional Demand Analysis of Residential Energy Consumption, 2008 Residential End Use Study, InterVISTAS Consulting Inc., April 15, 2009, p. 10.

The FEU remain committed to managing costs, but delivery rates pressure caused by declining throughput levels cannot be entirely offset by reduced operating costs. In this context, New Initiatives that complement the FEU's natural gas marketing efforts to mitigate the impact of declining throughput levels to customers become important in the FEU's drive to provide cost effective services and solutions to customers.

In the 2010-2011 RRA, FEI applied for O&M funding to increase resources tasked with identifying and attaching new customers and promoting the use of natural gas as a solution. This included additional sales and account management staff to provide existing and new customers with energy solutions. As stated on page 353 of the 2010-2011 RRA:

> *"To meet the changing customer and stakeholder expectations [FEI] is seeking incremental O&M of $4.5 million in 2010. Of this, the majority (over $4 million) is for additional sales and account management staff, additional staff in government relations, business development and analysis staffing, and additional customer advocacy staff. The remaining amounts are due to increase in staffing in the Regulatory Affairs Department and legal fees required to address regulatory and legislation changes and their impact. In 2011, to meet the customer and stakeholder expectations, [FEI] requires an additional $0.6 million for additional sales and account management staff in the Marketing Department."*

The Commission approved those resources in Order No. G-141-09, included in Appendix H of this Submission.

The request for this funding evidenced our shifting approach to responding to the challenges posed by our external marketplace. While continuing to focus on cost management, these new resources also looked to find new ways to make natural gas an accepted part of the energy solution in British Columbia. The development and promotion of New Initiatives is an important part of this push. The additional resources are helping the FEU to be more effective and to reach more customers and stakeholders than we otherwise would have been able to achieve.

2.1.6 Summary: New Initiatives are required to Mitigate Impact of Declining Throughput Levels

Historical trends and both internal and independent research suggest a continued decline in throughput levels in the years to come. Left unchecked, the loss of throughput and lower customer attachments will lead to higher rates for customers over time. In order to mitigate the risk of higher rates, FEU have brought forward various solutions, including the New Initiatives, with the intent of making natural gas and the use of its infrastructure a more attractive energy option for customers in the long term. As discussed in later Sections, it is intended that by providing New Initiatives, we can keep natural gas as part of the solution of delivering integrated energy solutions to customers: renewable and low-carbon thermal technologies for homes, businesses and institutional facilities (the built environment); natural gas as a low carbon transportation fuel alternative to diesel and gasoline; and the development of carbon neutral biogas to displace conventional natural gas for homes, businesses and potentially in vehicles. The FEU see the development of the New Initiatives as a key part of its low carbon strategy to help maintain our throughput levels, as well as meet British Columbia's energy objectives and focus on GHG emissions reduction targets and meet the changing needs of our customers, which are further discussed below.

2.2 POLICIES SUPPORTING PURSUIT OF NEW INITIATIVES

The Provincial government and a variety of local governments have increased their commitment to reducing GHG emissions by establishing aggressive GHG emissions reduction targets, and taking a leadership role in North America in the fight against climate change. These policies have put pressure on natural gas in its traditional role in providing heat for space and water heating even though it is one of the cleanest and lowest emitting fossil fuels. In this Section, the FEU address the key legislative developments and government policies having implications for both our customers and the FEU directly. In order for the FEU's efforts to maintain a role for natural gas to be successful, the FEU must deliver solutions that complement the evolving climate change policies. All of the New Initiatives support key provincial policies favouring reduced GHG emissions and the efficient use of energy.

2.2.1 The BC Energy Plan: A Vision for Clean Energy Leadership

The BC Energy Plan, released in 2007, is the cornerstone of the current provincial energy policy. The introduction of the 2007 BC Energy Plan (built on the 2002 Energy Plan) marked a significant change in the energy policy landscape in BC. Through the 2007 BC Energy Plan, the government demonstrated its commitment to the production of clean energy and reduction of GHG emissions in the province by leveraging the province's clean and renewable sources of energy. The BC Energy Plan also focused on British Columbians using energy more efficiently, and considering the "right fuel, for the right activity, at the right time".

The BC Energy Plan, among other things:

a) sets an ambitious conservation target to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020;

b) ensures that a coordinated approach to conservation and efficiency is actively pursued in British Columbia;

c) encourages utilities to pursue cost effective and competitive demand side management opportunities;

d) explores with BC utilities new rate structures that encourage energy efficiency and conservation;

e) implements Energy Efficiency Standards for Buildings by 2010;

f) integrates environmental design to new provincial public sector buildings to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard;

g) increases participation in the Community Action on Energy Efficiency program and expands the First Nations and Remote Community Clean Energy program;

h) produces net zero greenhouse gas emissions at all new electricity generating facilities constructed in British Columbia;

i) achieve a zero net greenhouse gas emissions from existing thermal generating power plants by 2016;

j) ensures clean or renewable electricity generation continues to account for at least 90 per cent of total generation;

k) ensures self-sufficiency to meet electricity needs by 2016, plus "insurance" power to supply unexpected demand thereafter;

l) establishes the Innovative Clean Energy Fund to support the development of clean power and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors;

m) implements a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages; and

n) implements a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.

The BC Energy Plan sets out ambitious targets, a strategy for reducing the province's GHG emissions and a commitment to unprecedented investments in alternative energy technology.

An important element of the BC Energy Plan is its support for using "the right fuel, for the right activity, at the right time". The BC Energy Plan set out this principle on page 22:

> *"It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of alternative energy sources with natural gas include solar thermal and geothermal. Working with municipalities, utilities and other stakeholders the provincial government will promote energy efficiency and alternative energy systems, such as solar thermal and geothermal throughout the province."*

Furthermore, the BC Energy Plan recognizes the importance of natural gas in promoting competitiveness in the Province and encourages the "development of unconventional resources such as tight gas, shale gas, and coalbed gas".

To demonstrate its commitment to the reduction of GHG emissions and creation of employment, the government established the Innovative Clean Energy ("ICE") Fund. The ICE Fund supports investment in alternative energy solutions to support local economies and livelihoods in communities across British Columbia. Since 2008, the ICE Fund has been investing over $60 million in 41 projects in communities across BC, representing a total value of over $234 million, to help develop clean and renewable energy technologies in areas like solar, geothermal, tidal, wind and bioenergy[28].

Under the BC Energy Plan, utilities are encouraged to pursue all cost effective investments in EEC and to develop a diversified portfolio of programs to ensure all ratepayers can benefit from these programs. Also, all utilities are asked to explore, develop and propose to the Commission additional innovative rate designs that encourage efficiency, conservation and the development of clean or renewable energy, which includes building upon "natural bioenergy resource advantage".

Furthermore, in the BC Energy Plan, the government indicates its commitment to reducing GHG emissions from the transportation sector. The BC Energy Plan highlights that "natural gas burns cleaner than either gasoline or propane, resulting in less air pollution" (page 19) implying that the adoption of NGVs can play a role in helping the province reduce GHG emissions in the transportation sector.

The introduction of the BC Energy Plan had several key implications for the FEU and other utilities, including the following:

- First, the overall policy environment in BC has undergone a shift towards low carbon solutions. This impacts all British Columbians, a significant percentage of whom are customers of the FEU. As these customers and potential customers look to respond to policy and legislative initiatives from Government, they will turn to utilities as a source of expertise. As discussed later in the context of customer expectations, a growing segment of the FEU's customers want the FEU to be involved in providing information and comprehensive energy solutions.

- Second there is general policy support for pursuing alternative energy solutions as a means of addressing climate change and energy needs over the longer-term.

- Third, the policy and legislative framework itself contemplates that public utilities will play a key role in the delivery of energy solutions and measures intended to improve the efficient use of energy. DSM, which the FEU also refer to as EEC, is identified expressly in the policy actions in the BC Energy Plan, as is the use of innovative rate structures.

---

28 BC Ministry of Energy and Mines and Responsible for Housing, http://www.empr.gov.bc.ca/EAED/ICEFund/Pages/About.aspx.

Provincial legislation enacted to give effect to the BC Energy Plan reinforces each of the three points outlined above. Various legislation and its implications are further discussed below.

2.2.2 *Greenhouse Gas Reduction Targets Act* and Offset Emissions Regulation

As part of the BC Throne Speech delivered on February 13, 2007, the government first announced targets for provincial GHG reductions. Effective January 1, 2008, the *Greenhouse Gas Reductions Targets Act ("GGRTA")* established the provincial government's commitment to becoming carbon neutral, and set province wide targets for GHG emissions reductions of:

- 33% from the 2007 level by 2020, and
- 80% from the 2007 level by 2050.

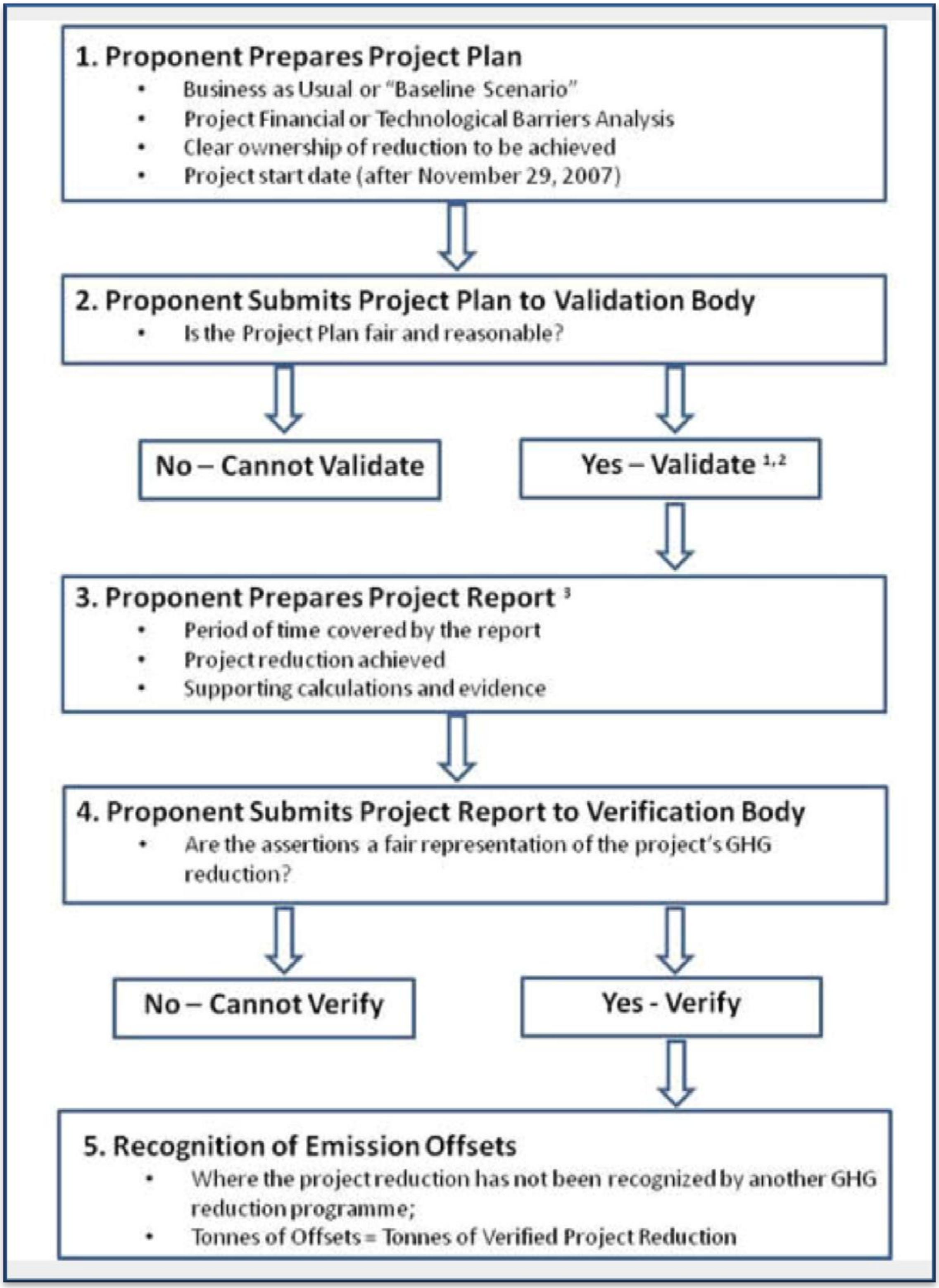
On November 25, 2008, further GHG interim targets were set by Ministerial Order to:

- 6% below 2007 levels by 2012, and
- 16% below the 2007 levels by 2016.

The *Greenhouse Gas Reductions Targets Act* made BC the first jurisdiction in North America to make a legally binding commitment to carbon neutral operations.

In addition to setting GHG emissions reduction targets, the government has established a regulation addressing the quality of GHG offsets in BC. Under the provisions of the *GGRTA*, the *Emission Offsets Regulation* came into effect on December 9, 2008. The Emission Offsets Regulation sets out requirements for GHG emissions reductions and removals from projects or actions to be recognized as emission offsets for the purposes of fulfilling the provincial government's commitment to a carbon-neutral public sector. Offsets represent emission reductions or removals through projects such as renewable energy generation and energy efficiency initiatives. The Pacific Carbon Trust, acting on behalf of the Province of BC, acquires GHG offsets from projects that are located in BC and that meet provincial eligibility criteria as defined by the Offset Emissions Regulation. Figure 2-13 below summarizes the offset project process as set out in the Offset Emissions Regulation.

Figure 2-13: Offsets Project Process Summary



Source: BC Ministry of Environment, http://www.env.gov.bc.ca/cas/mitigation/ggrta/faqs.html

With the *GGRTA* in place, the Province has a pressing need to support innovative measures to reduce BC's GHG emissions. Other key legislative initiatives are the *Carbon Tax Act* and amendments to the *Utilities Commission Act*, both discussed below.

2.2.3 *Carbon Tax Act*

In July 2008, the BC government became the first jurisdiction in North America to introduce a consumer–based carbon tax on the purchase of fossil fuels including natural gas. Through the use of price signals the carbon tax is intended to encourage consumers to reduce their use of fossil fuels and related emissions, thus influencing individuals and businesses to make more environmentally responsible choices. The tax is calculated based on $10 per tonne of carbon dioxide-equivalent emissions released from burning fossil fuels, with increases of $5 per tonne over the following four years, reaching $30 per tonne as of July 1, 2012. This resulted in the addition of $0.50 per gigajoule ("GJ") to the cost of natural gas in the first year, rising to an additional $1.50/GJ after 4 years from the date of implementation. It is projected that this tax will generate revenues of approximately $1.85 billion over the first three years for the BC government, and will help it achieve approximately 7.5 percent of its legislated GHG emissions reduction targets by 2020, while providing consumers with a choice on how they wish to adapt their behaviour to reduce fossil fuel consumption.

Potential for carbon tax increases and the level of tax beyond 2012 remain uncertain at this time. However, in a report entitled "Meeting British Columbia's Targets: A report from the B.C. Climate Action Team", the Climate Action Team recommended that:

> *"After 2012, if required to achieve the emissions targets, increase the British Columbia carbon tax in a manner that aligns with the policies of other jurisdictions and key economic facts*".

In other words, it would be reasonable to assume a future rise in carbon tax if emission targets are not met. Some reports indicate that carbon taxes may need to go up to $300 per tonne in order to have a meaningful impact on consumer behaviour and therefore reduce GHG emissions. Also, a recent publication by the Pembina Institute states: "If the carbon tax is going to be a key part of B.C.'s energy revolution, then it needs to continue increasing – fossil fuels are too cheap and plentiful to hope that change will just happen without an increase" [29]. We believe that the carbon tax will have the effect of providing a long term price signal to customers so that they will continue to make the choices required to reduce their fossil fuel use and emissions.

Over the past year, the FEU have been working with the provincial government to resolve the issue on whether or not Biomethane is carbon tax exempt. The *Budget Measures Implementation Act, 2011* ("Bill 2") is currently before the legislature. Section 3 of Bill 2 amends

[29] The Pembina Institute, http://www.pembina.org/op-ed/2246.

the *Carbon Tax Act* to certify Biomethane as a carbon-neutral fuel and to insert the language allowing the implementation of the Biomethane credit promised in the 2011 provincial Budget. The FEU have discussed the implementation of the credit with the Ministry of Finance and received direction that we may proceed with our plan to provide the credit to customers on their bills prior to Bill 2's passage in the legislature.

With the passage of the *Carbon Tax Act*, there is a renewed impetus for our customers to make efforts to reduce their carbon footprint. As discussed later in this Section, many customers are looking to the FEU to provide solutions. Based on the amendments to the *Utilities Commission Act* discussed below, the Province has placed public utilities front and centre in the effort to combat GHG emissions and improve the efficient use of energy in BC.

2.2.4 Amendments to the *Utilities Commission Act*

In 2008, the BC government enacted amendments to the *Utilities Commission Act* to reflect the "government's energy objectives". The "government's energy objectives" set out in the amended *UCA* were then replaced by "British Columbia's energy objectives" as set out in the *Clean Energy Act* (the "*CEA*", see Section 2.2.6).

The original "government's energy objectives" were:

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

b) to encourage public utilities to take demand-side measures;

c) to encourage public utilities to produce, generate and acquire electricity from clean or renewable sources;

d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility;

e) to encourage public utilities to use innovative energy technologies

    i. that facilitate electricity self-sufficiency or the fulfillment of their long-term transmission requirements, or

    ii. that support energy conservation or efficiency or the use of clean or renewable sources of energy; and

f) to encourage public utilities to take prescribed actions in support of any other goals prescribed by regulation.

Since the amendments to the *UCA* in 2008, the Commission has been required to consider "government's energy objectives" (and now British Columbia's energy objectives) in the context of long term plans, applications for a CPCN, applications for approval of expenditure schedules and energy purchase contracts. For instance, the Commission, in their Decision, Order No. G-14-11 (dated February 1, 2011) for the FEU's 2010 Long Term Resource Plan, stated:

> *"In assessing the 2010 LTRP in terms of its requirements and considering the British Columbia energy objectives and policy as well as the evidence before it, the Commission Panel accepts the [FEU] 2010 LTRP under section 44.1 (6) of the UCA as being in the public interest."* [30]

2.2.5 BC Climate Action Charter and Municipal Government Commitments

Under the *Greenhouse Gas Reduction Targets Act*, the BC government is legally committed to becoming carbon neutral by 2012. To support the government's energy and climate change objectives, local governments from across BC have joined with the Province and the Union of BC Municipalities by committing to the British Columbia Climate Action Charter. The Charter pledges to significantly cut GHG emissions by 2012 through carbon neutrality. Carbon neutrality means having no net emissions of GHGs, generally achieved through reducing GHG emissions where possible, by investing in projects that eliminate GHG emissions, and capturing and containing GHG emissions. So far 179 local governments and the Islands Trust have signed the Charter and these signatories commit to carbon neutrality in internal operations by 2012, measuring and reporting on community GHG emissions profile, and creating complete, compact, more energy efficient communities[31]. Those communities that have signed on to the charter have access to the Climate Action Revenue Incentive Program that offsets the carbon tax for local governments.

The two largest municipalities in BC — Vancouver and Surrey — have made significant commitments to achieve carbon neutrality and long term goals on reducing carbon footprint.

The City of Vancouver has an action plan for becoming the world's greenest city by 2020. In order to progress toward an environmentally sustainable future, the City of Vancouver is developing plans for, among other things, a green economy, energy-efficient buildings, clean transportation, and urban forest management. The City's goal is to position Vancouver as a Green Capital – a hotbed of green commerce and innovation. The action plan focuses on three areas: a green economy and green jobs, greener communities, and human health. The City of Vancouver's general strategy to achieve carbon neutrality from its own operations is to use best practices to reduce emissions from civic buildings, fleet, and solid waste and to offset remaining emissions by developing incremental, verifiable GHG emissions reduction projects and programs in the local community. As a part of this strategy, the City discourages natural gas consumption. Various tools are employed, including the Green Homes Program, for construction of one- and two-family homes, which includes bylaws limiting the types of gas fireplaces that are acceptable for installation. Another tool is the use of rezoning application conditions for large scale rezone applications (2 acres and over) under EcoCity Policies. Under these policies,

---

30 Order No. G-14-11, dated February 1, 2011, included in Appendix H.
31 LiveSmartBC Climate Action Charter, http://www.livesmartbc.ca/community/charter.html.

distributed heat generating equipment – including gas-fired make-up heaters – are not allowed. The same prohibition applies to heat producing fireplaces. These policies directly and detrimentally impact the FEU's gas business. As such, it is incumbent upon the FEU to ensure alternate offerings outside of natural gas can help mitigate these impacts, while also helping municipalities and the Province meet their energy and sustainability objectives. In following Vancouver's lead as the world's new Green Capital, other municipalities in British Columbia and elsewhere will adopt similar initiatives following in Vancouver's footsteps and leverage on opportunities that the City of Vancouver creates.

The City of Surrey, as one of the fastest growing municipalities in BC, continues to work on becoming a greener and more sustainable city, positioning itself as a premier investment location and leader in the sustainability sector, specifically by becoming an appealing location choice for clean technology companies. Surrey's Sustainability Charter is the first document of its kind in the Lower Mainland and is designed to guide the City's approach to social, cultural, environmental and economic sustainability. The Sustainability Charter outlines specific goals for achieving the vision for and commitment to sustainability. As part of its sustainability initiatives, the city of "Surrey incorporates "Triple Bottom Line Accounting" into its operations, incorporates and encourages alternative energy sources, and strives for carbon neutrality and no net impact from waste*".* The City will seek ways to reduce the use of fossil fuels and to be carbon neutral, through a wide range of alternative energy sources that focus on renewable energy. These may include district heating systems, wind, active and passive solar, biomass, waste to energy and geo-exchange heating and cooling. Most resources will be produced locally, recycled or reused. Most recently, the City, through bylaws, has created its own district energy business to deliver geothermal energy to the new city hall and new city library. The goal of the City is to expand this low carbon energy system to deliver heat to a larger section of Surrey.

The FEU recognize that municipalities have great potential to affect changes in energy behavior and consumption, as they directly control land use in urban and suburban areas. We believe that by partnering with municipalities and regional districts, we can play a role in helping them meet the provincial energy objectives related to reducing GHG emissions and energy efficiency. Also, several municipalities have recognized the fact that the FEU have a prominent role in providing new products and services to energy consumers in meeting these goals and have therefore entered into discussion with the FEU to evaluate potential alternatives and projects. The FEU's ability to invest in New Initiatives and integrated energy solutions can reduce or eliminate the municipality's capital requirement, thus enabling the municipality to meet their climate action obligations on projects that might not otherwise have been possible due to municipal budgetary constraints.

The FEU's partnership with municipalities can begin with participation in the development of the Community Energy and Emissions Plan ("CEEP") or it may simply take the form of a consultative process, meeting with municipal officials to hear about their strategies for meeting their GHG emissions reduction goals. It can also take the form of Memorandum of Understanding ("MOU") with municipalities to work together towards "green" energy objectives. We are presently in consultation with many cities, towns, regional districts and other stakeholders around British Columbia. A number of these consultations have resulted in the identification of projects to reduce GHG emissions and increase efficient energy use. A few specific developments are:

Biomethane: An anaerobic digester in Abbotsford and a landfill gas capture system in Salmon Arm are producing real reductions in GHG emissions in those communities. At the same time these projects are contributing Biomethane to our distribution system, allowing residential (and potentially commercial) gas users to participate in GHG emissions reductions by displacing a portion of their natural gas consumption with Biomethane.

Natural Gas Vehicles: A private trucking company in Abbotsford (Vedder) has purchased 50 LNG trucks, reducing GHG emissions in that community and around the Province. Our Energy Efficiency and Conservation program will offset the incremental cost of using LNG-powered trucks rather than their traditional diesel counterparts.

Thermal Energy Services: Developers, municipalities and school districts in BC now look to FEI to own and operate equipment that produces thermal energy at their sites using technologies that reduce energy consumption by both switching to the use of clean, renewable energy sources and more efficiently utilizing energy overall. While FEI is already operating some discrete geo-exchange systems, development work is currently in progress to evaluate DES systems in many municipalities and packages of thermal energy systems in discrete sites throughout many school districts.

Energy Efficiency and Conservation: EEC funding supports municipalities that wish to upgrade their own facilities, as municipalities would be eligible to participate in incentive programs. We have provided funding to the Community Energy Association and have co-funded various pilot programs launched by the City of Vancouver.

Such measures by the FEU, government, and the private sector not only exemplify British Columbia's leadership in addressing the challenging energy and climate objectives, but also demonstrate British Columbia's commitment to ensuring the Province becomes a low carbon economy.

2.2.6 *Clean Energy Act*

On April 28, 2010, the BC government announced the *Clean Energy Act* ("*CEA*") (Bill 17), which aims to ensure electricity self-sufficiency at low electricity rates by 2016, to harness BC's clean power potential to create jobs, and to strengthen environmental stewardship and reduce GHG emissions. Section 2 of the *CEA* sets out BC's new energy objectives, almost all of which have implications for energy efficiency and optimization, and carbon reduction solutions. These new "British Columbia's energy objectives" replaced and enhanced "government's energy objectives" in the *Utilities Commission Act*, and have implications for the role of public utilities generally in delivering on the provincial government's initiative to reduce GHG emissions and improve energy efficiency.

The *CEA* is supportive of alternative energy and establishes the implementation of feed-in tariffs to encourage the production of power from alternative sources in the Province. The *Clean Energy Act's* new definition for "demand side measure" excludes electricity-to-gas fuel switching as an option.

While the *CEA* does not promote the use of natural gas over electricity for thermal uses, neither does it preclude the use of natural gas over electricity, recognizing the important role that both energy types play in meeting BC's energy and resource needs. With the current focus of the provincial government and media on electricity in BC as a renewable energy source, there may be confusion about the role of natural gas among customers and stakeholders.

The *CEA* seeks to address a number of impediments in the existing legislative and regulatory framework to achieving the Province's goal of becoming a green energy powerhouse. However, much of what is expressed in the *CEA* is an extension of previously stated or referenced government priorities, many of which have been discussed above. The *CEA* also leaves open quite a number of areas for future determination through the issuance of regulations by the Minister or the Lieutenant Governor in Council.

The *Clean Energy Act* does not establish as a specific objective the reduction of total volume of gas usage in the Province, but it does encourage efficient use of energy and the reduction of GHG emissions. In some instances, these objectives can be achieved through reducing gas usage, and Energy Efficiency and Conservation programs support this approach. In other instances, however, increased natural gas consumption may complement the objectives of encouraging energy efficiency and reducing GHG emissions. For instance, natural gas is a lower carbon fuel for transportation. The Biomethane offering supports several specified objectives in the *Clean Energy Act* and complements EEC programs emphasis on the efficient use of energy by substituting a renewable carbon neutral fuel (Biomethane) for a non-renewable carbon-emitting fuel (natural gas), thus producing a net reduction in GHG emissions based on the same overall consumption. The following Sections outline how the FEU's New Initiatives advance "British Columbia's energy objectives".

2.2.6.1 British Columbia's Energy Objectives as they Relate to Biomethane Service

Table 2-5 below identifies the "British Columbia's energy objectives" relevant to a Biomethane service offering. The right hand column explains, in summary form, why the proposals for our Biomethane service, including the FEU's ownership of upgrading facilities, are consistent with or promote "British Columbia's energy objectives". In the Biomethane Decision[32], the Commission

[32] Order No. G-194-10, dated December 14, 2010, included in Appendix H.

stated that "*… the Application is consistent with British Columbia's energy objectives and Provincial Government energy policy*".

Table 2-5: Biomethane Service Advances British Columbia's Energy Objectives

"British Columbia's Energy Objectives"	Reference to *CEA*	How our Biomethane Service Addresses "British Columbia's Energy Objectives"
"to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources"	*CEA* s.2(d)	We have created a market for Biomethane, a previously unused innovative source of clean and renewable energy in British Columbia.
"to reduce BC greenhouse gas emissions"	*CEA* s.2(g)	The development and use of Biomethane is carbon neutral. The use of Biomethane in place of a carbon positive energy source, such as natural gas, will lead to reduced GHG emissions in BC.
"to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia"	*CEA* s.2(h)	The switching from conventional natural gas to Biomethane will lead to reduced GHG emissions in BC.
"to encourage communities to reduce greenhouse gas emissions and use energy efficiently"	*CEA* s. 2(i)	We partner with municipalities and regional districts to allow them to reduce their GHG emissions through the upgrading of their waste methane (Biogas) to pipeline quality Biomethane.
"to reduce waste by encouraging the use of waste heat, biogas and biomass"	*CEA* s. 2(j)	The upgrading of currently wasted Biogas to Biomethane, and its injection into our distribution system, will allow its use by customers on our distribution system.
"to encourage economic development and the creation and retention of jobs"	*CEA* s. 2(k)	We used made-in-BC technology for the Salmon Arm landfill project. Furthermore, the Catalyst Power Inc. project is directly creating the employment of the entrepreneurs who are responsible for the development of that project.
"to foster the development of first nation and rural communities through the use and development of clean or renewable resources"	*CEA* s. 2(l)	We partner with municipalities and regional districts, and will seek out further such partnerships that may also include First Nations communities for the development of clean and renewable Biomethane supply projects.

2.2.6.2 British Columbia's Energy Objectives as they Relate to Natural Gas Vehicles Service

Table 2-6 below identifies the "British Columbia's energy objectives" relevant to NGV Service. The right hand column explains, in summary form, why the NGV fueling services (CNG/LNG), which involve the FEU's ownership and operation of fueling facilities, are consistent with or promote "British Columbia's energy objectives". The Commission's recent NGV Decision[33], recognized that "*fuel switching from diesel to natural gas will assist the province in meeting its energy objectives*", and highlighted its benefits of GHG emissions reduction.

Table 2-6: NGV Fueling Service Advances British Columbia's Energy Objectives

"British Columbia's Energy Objectives"	Reference to *CEA*	How our NGV Fueling Service Addresses "British Columbia's Energy Objectives"
"to reduce BC greenhouse gas emissions"	*CEA* s.2(g)	Low-carbon NGVs in WM Agreement result in 23% fewer emissions than diesel equivalent vehicles.
"to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia"	*CEA* s.2(h)	WM Agreement facilitates Waste Management fuel switching from diesel to CNG. This results in approximately 214 fewer tonnes of CO2e per year.
"to encourage communities to reduce greenhouse gas emissions and use energy efficiently"	*CEA* s. 2(i)	Waste Management is replacing high-carbon, diesel emitting waste haulers - which operate in Lower Mainland communities - with low-carbon NGVs.
"to encourage economic development and the creation and retention of jobs"	*CEA* s. 2(k)	Supports economic development and job creation for BC-based NGV engine manufacturer Westport Innovations, CNG station manufacturer IMW industries, and various engine conversion installers.

2.2.6.3 British Columbia's Energy Objectives as they Relate to TES

Table 2-7 below identifies the "British Columbia's energy objectives" relevant to TES. The right hand column explains, in summary form, why the proposals for our Thermal Energy Services are consistent with or promote "British Columbia's energy objectives".

[33] Order No. G-128-11, dated July 19, 2011, included in Appendix H.

Table 2-7: TES Advances British Columbia's Energy Objectives

"British Columbia's Energy Objectives"	Reference to *CEA*	How our Thermal Energy Services Addresses "British Columbia's Energy Objectives"
"to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources"	*CEA* s.2(d)	We are proposing to create a market for thermal energy services, which are sources of clean and renewable energy in British Columbia.
"to reduce BC greenhouse gas emissions"	*CEA* s.2(g)	The development and use of geothermal, solar and district energy solutions is carbon neutral or less carbon intensive. Their use of in place of a carbon positive energy source, such as natural gas, will lead to reduced GHG emissions in BC.
"to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia"	*CEA* s.2(h)	The switching from conventional natural gas to thermal energy will lead to reduced GHG emissions in BC.
"to encourage communities to reduce greenhouse gas emissions and use energy efficiently"	*CEA* s. 2(i)	The provision of thermal energy services in combination with natural gas will allow their use by customers on our distribution system.
"To reduce waste by encouraging the use of waste heat, biogas and biomass"	*CEA* s 2(j)	District energy systems will allow the use of waste biomass such as that caused by pine beetles as well as biomethane.
"to encourage economic development and the creation and retention of jobs"	*CEA* s. 2(k)	We are proposing to use made-in-BC technology and employ local people on the projects creating the employment of the entrepreneurs who are responsible for the construction of that project.
"to foster the development of first nation and rural communities through the use and development of clean or renewable resources"	*CEA* s. 2(l)	We propose to partner with developers, municipalities, regional districts, and First Nations communities for the development of clean and renewable thermal energy services.

2.2.6.4 British Columbia's Energy Objectives as they Relate to Energy Efficiency and Conservation Initiatives

Table 2-8 below identifies the "British Columbia's energy objectives" relevant to EEC. The right hand column explains, in summary form, why the EEC initiatives are consistent with or promote "British Columbia's energy objectives". As discussed in later Sections, EEC activities support the legislated objectives[34], but this discussion provides useful context.

[34] At the time of the EEC Decision, the relevant objectives were "government's energy objectives". There is substantial overlap.

Table 2-8: EEC Initiatives Advances British Columbia's Energy Objectives

"British Columbia's Energy Objectives"	Reference to *CEA*	How our EEC Initiatives Addresses "British Columbia's Energy Objectives"
"to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources"	*CEA* s.2(d)	EEC conducts pre-feasibility studies, initiates market assessments, engages the trades and manufacturer communities, and educates residential, commercial, and industrial customers about the advantages of innovative technologies and provides incentives for their adoption when necessary.
"to reduce BC greenhouse gas emissions"	*CEA* s.2(g)	EEC programs delivered through incentives and education enable customers to implement measures to reduce their natural gas consumption and GHG emissions.
"to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia"	*CEA* s.2(h)	This objective is supported through the EEC High Carbon Fuel Switching program area initiatives. These initiatives are designed to result in lower overall GHG emissions by moving existing customers away from fossil fuels with a higher carbon content than natural gas to natural gas Energy Star or Enerchoice rated appliances. These programs are delivered through incentives and education.
"to encourage communities to reduce greenhouse gas emissions and use energy efficiently"	*CEA* s. 2(i)	The EEC Conservation Education and Outreach program area is intended to foster and develop a culture of conservation in BC and supports this objective by encouraging customers on small steps to energy conservation through a variety of initiatives, such as print and online media communications, outreach at trade shows and community events, behavior change programs, and school programs.
"to encourage economic development and the creation and retention of jobs"	*CEA* s. 2(k)	In addition to the direct impact of employing staff to develop and implement EEC initiatives, EEC programs also have broad impacts on the provincial economy as measured through metrics such as employment, GDP, and industrial output. Impacts arise from short term investment activities, such as building retrofits, and longer term changes in household/business spending, which can be attributed to the persistence of energy savings.

2.2.7 Summary: BC Policy Environment has Implications for Natural Gas and Therefore the Need for New Initiatives

The BC Energy Plan makes clear that there is a role for natural gas in British Columbia's overall energy picture. At the same time, the introduction of the BC Energy Plan, the *Clean Energy Act* and supporting legislation has had implications for customers and potential customers of the FEU, and has placed public utilities like the FEU in the forefront of providing innovative solutions to address GHG emissions reduction targets and energy efficiency policies and goals. These policies have had an impact on natural gas in its traditional role, and many have challenged the role of natural gas in meeting these policies and energy objectives. For example, BCOAPO's statement in its final argument in the BC Hydro 2008 LTAP proceeding stated:

> *"British Columbia is blessed with a rich hydrology that lends itself well to hydroelectric generation projects, both large and small and as a result, we do not as a province rely on dirty coal or natural gas generation for our power as do most jurisdictions in the world. Why then, when governments across the continent and around the world are adopting strong messages to avoid a climate catastrophe, and our provincial government has set its own aggressive GHG emission reduction goals, and our population is concerned about air quality, pollution, and climate change, would we support our relatively clean hydroelectric utility embarking upon a program that would encourage their current and future customers to switch to natural gas? In short: we shouldn't, we wouldn't, and we don't*." [35]

This statement shows how the provincial and local government GHG emissions targets can influence and shape customers perception against natural gas despite the direct economic benefits. Changed customer views and are likely to contribute to challenge the FEU to address the declining throughput issues discussed in Section 2.1.

The FEU's New Initiatives are a response to the challenges and opportunities presented by the ever-changing climate change policies, recognizing that natural gas continues to be a foundational fuel and should have a role in meeting energy needs and energy objectives. It is also important to note (as discussed later in this Section) that these policy changes are in part a result of the demands of British Columbians, and by extension customers of the FEU. While these policies are an important factor in directing the FEU to pursue the New Initiatives, equally important are the desires of our customers. Customers and consumers believe that the FEU should be pursuing the New Initiatives (see Section 2.4) and we believe that we better meet our customers' needs by offering both gas and New Initiatives, such as TES. As the Canadian Gas Association has noted, given that natural gas is "abundant, affordable, safe, clean, and reliable", the role of natural gas within the energy mix will continue to be explored, "both as a primary energy source and the enabler of innovative alternatives"[36]. As such, the policy framework supports the FEU's involvement in the New Initiatives, customer demands support both the

---

[35] BCOAPO, Final Argument in BC Hydro 2008 LTAP, dated April 27, 2009, page 7-8.

policy framework and the New Initiatives, and the New Initiatives in turn support the advancement of provincial policy.

2.3 THE ENERGY ENVIRONMENT IN BC

Government energy policies and legislation have the potential to greatly influence the direction of how energy will be produced and on the energy choices that customers make now and into the future. BC is one of the biggest natural gas producers in the country and is expected to increase even further with government's focus on its importance in generating economic wealth and meeting rising energy demand. Recent analysis shows that by 2015, almost twice as much (3.5 billion cubic feet ("Bcf") – per day) capacity could be built to flow natural gas west into Alberta and off shore to global markets than is expected to be produced (1.9 Bcf per day) in BC today[37]. With the importance of its economic value to the Province, we will see a rise in natural gas in BC, which will result in higher GHG emissions. This means that significant reduction of GHG emissions will have to come from other sectors. This Section explores the energy use and GHG emissions profile in BC as well as competing energy challenges faced by natural gas utilities due to use of clean hydro-electricity in the Province and low electricity rates in BC. This energy production and consumption environment is what differentiates BC from other jurisdictions and is why BC's energy solutions to GHG emissions reductions are unique.

2.3.1 Energy Use and GHG Emissions Reduction Opportunities in BC

The increasing energy policy and regulation focusing on reducing GHG emissions in BC have an impact on utilities by mandating reduction targets or setting performance standards in producing and delivering energy to consumers and focusing on shifting energy use to reduce GHG emissions. This will result in increased cost for the utilities to comply with these new regulations over time and therefore require an extension to service offerings such as Biomethane, NGV, and TES. How GHG emissions are generated in each jurisdiction is important because it gives an indication of potential areas where GHG emissions reductions will be targeted over time.

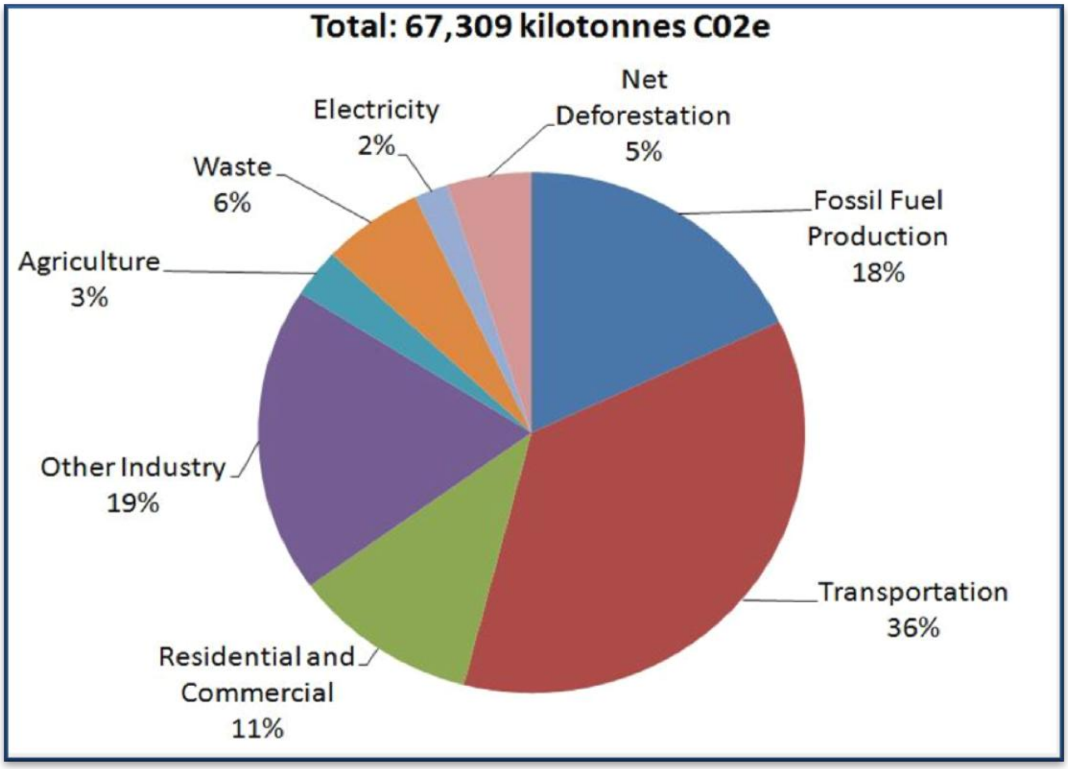
As demonstrated in Figure 2-14 below, in 2007 BC produced over 67 million tonnes of GHG emissions. With the BC government focusing on economic prosperity and stimulating growth in oil and gas sector, it will be a significant challenge for BC to reduce GHG emissions from the fossil fuel production sector (18 percent). This leaves the transportation sector at 36 percent, other industry at 19 percent, and the residential and commercial sector at 11 percent as the potential areas for significant reductions in GHG emissions. By default this puts the FEU's natural gas business at risk from the Province's GHG emissions reduction targets policy.

---

[36] Canadian Gas Association, Natural Gas: Our Place in Canada's Sustainable Energy Future http://www.cga.ca/pdfs/CGA%20Gas%20in%20the%20Future%20-%20Final%20Feb%207,%202011.pdf

[37] Please refer to excerpts from the 2010 Resource Plan included in Appendix A.

Figure 2-14: GHG Emissions Profile in BC (2007)

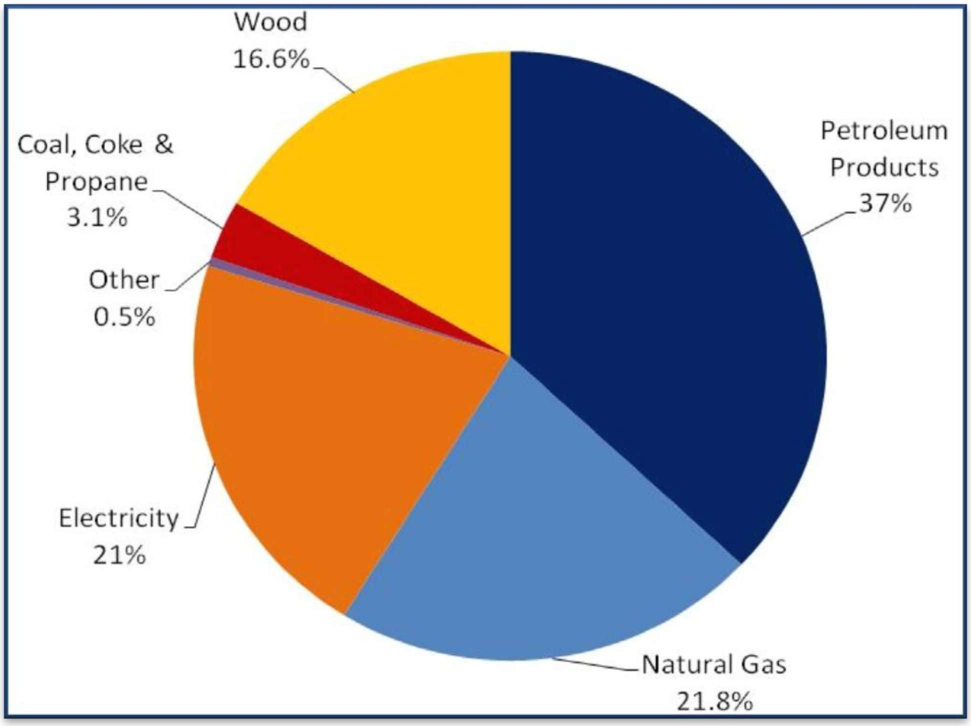


Source: LiveSmart BC website

This GHG emissions profile is significantly different from other jurisdictions, such as Alberta. Whereas electricity generation contributes to two per cent of BC's total emissions, in Alberta, electricity and heat generation result in approximately 23 percent of total GHG emissions (based on 2006 figures). The main reason for this difference is that Alberta's electricity generation consumption requirements are met almost exclusively by the combustion of coal (62 percent in 2007) while BC has an extensive use of hydro-electric power (further discussed below in Section 2.3.2). Similar to BC, the Province of Alberta has also put in place GHG emissions intensity targets effective July 1, 2007. Given that natural gas is the cleanest and lowest carbon fossil fuel, it can significantly reduce GHG emissions. As a result, expanding the use of natural gas, particularly for electricity generation as well as direct use applications such as home heating and appliances, is very much encouraged in Alberta and other jurisdictions alike. The fundamental difference in how GHG emissions are produced in each jurisdiction can lead to different solutions in how to go about reducing GHG emissions as a whole. In Alberta the direct use of natural gas would be a solution to the GHG emissions problem because by consuming natural gas directly less emissions are produced rather than using electricity that is produced from coal or natural gas. In BC, because electricity is seen as almost 100 percent "clean", customers and stakeholders see electricity as the path to meet the climate change goals. This puts natural gas utilities like the FEU at the forefront in moving alternative solutions forward to customers, more so than our counterparts in other parts of Canada, or the US, because of these fundamental differences in how GHG emissions are produced within each jurisdiction.

Figure 2-15 below shows the current end-use energy sources for BC.

Figure 2-15: BC Energy End-Use



Source: NRCAN 2007 Stats

Looking forward, renewable and low carbon end-use energy alternatives will have a prominent role to play in meeting the growing need for energy in BC and natural gas will have a role in this new energy mix. According to the Canadian Gas Association:

> *"Going forward, natural gas will continue to play a key role as Canada seeks to ensure the sustainability and environmental responsibility of its energy supply, reduce energy-related costs, and reap the benefits of greater efficiency. The exceptional versatility of natural gas — with uses ranging from industry to transportation, from single buildings to the community-wide energy grid — makes it a truly foundational fuel."* [38]

Consequently, the FEU's New Initiatives are all aimed at meeting GHG emissions reduction objectives as well as meeting the growing energy need in the Province, while trying to make use of existing natural gas infrastructure to protect against the decline in total throughput as outlined in Section 2.1.

---

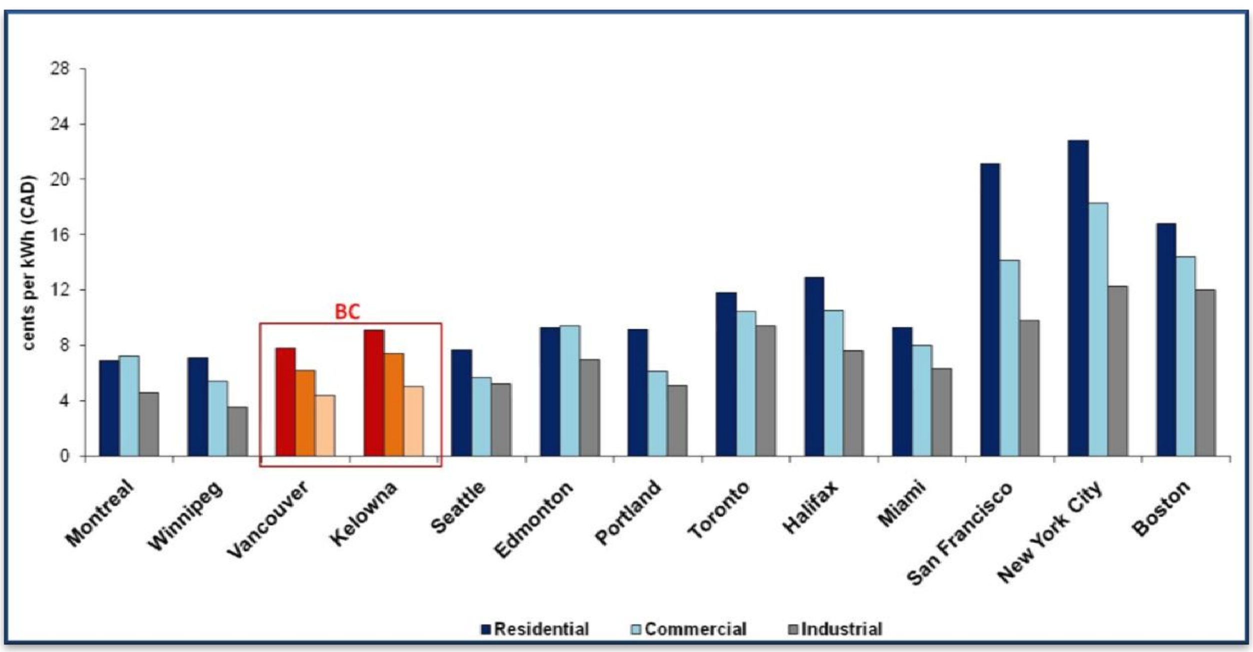
[38] Canadian Gas Association, Natural Gas: Our Place in Canada's Sustainable Energy Future http://www.cga.ca/pdfs/CGA%20Gas%20in%20the%20Future%20-%20Final%20Feb%207,%202011.pdf

2.3.2 BC Electricity Shifts Energy Demand and Impacts GHG Emissions

In BC, the presence of major hydro-electric production and the very small amount of fossil fuel fired electric production sets the Province apart from other jurisdictions where natural gas is distributed. Most of BC's electricity is produced from renewable sources of electricity generation that have been significantly depreciated (with up to 15 percent of the electricity consumed being imported electricity produced in other jurisdictions, which likely is produced from a fossil fuel) while other jurisdictions produce most of their electricity from a combination of coal and natural gas that is market priced. In jurisdictions such as Alberta, natural gas is expected to act as the transition fuel for both electricity generation and direct use applications. This view results from the fact that natural gas is the cleanest and lowest carbon fossil fuel, and from the relative lack of regional renewable electricity generation resources outside of BC. Therefore, the competitive position of the FEU against electricity is different from other natural gas utilities in other parts of North America.

Additionally, BC Hydro's relatively flat electricity rates have had a price advantage over natural gas for many years. One of the main reasons for this price advantage is the manner in which these products are priced in BC. Natural gas commodity pricing for consumers in BC is market-based whereas a large percentage of the costs making up electricity rates are the low embedded costs of BC Hydro's Heritage generation facilities. Figure 2-16 below shows that BC Hydro's electrical rates are among the lowest electricity rates in North America.

Figure 2-16: Electricity Rates Across North America



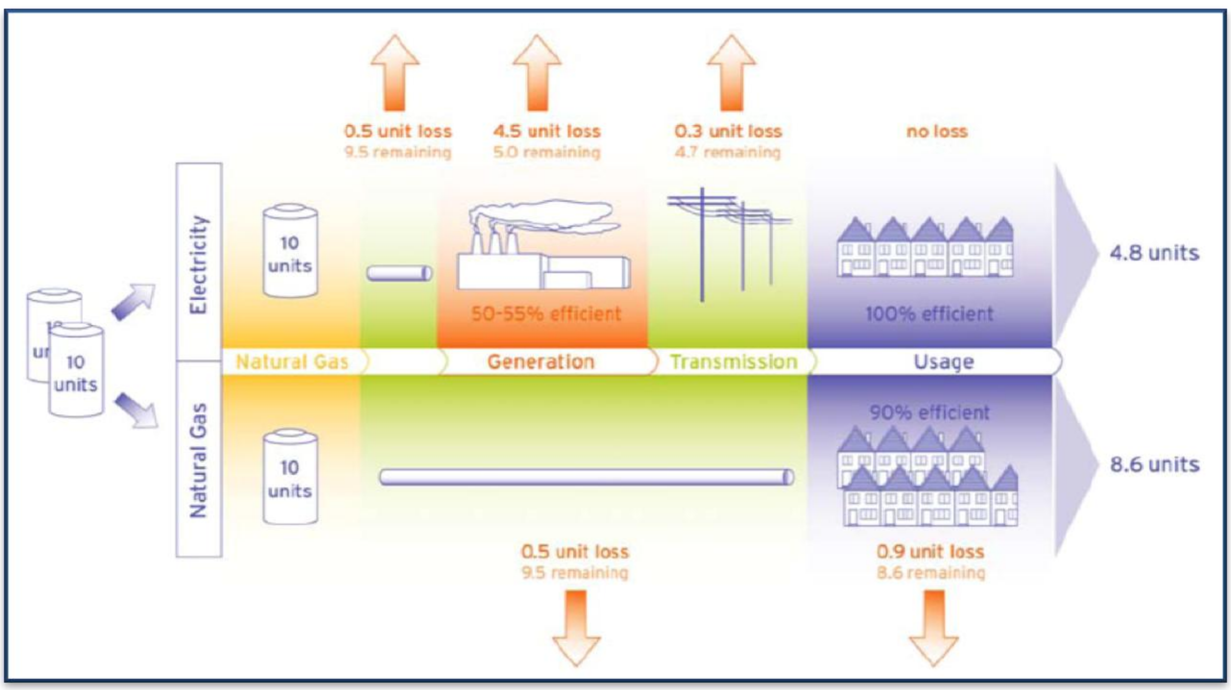
Furthermore, given that electricity is not subject to the carbon tax in BC, natural gas and other fossil fuel consumption in BC is disadvantaged from a price point of view as compared to electricity, and the carbon tax will help to sensitize customers to the level of GHG emissions they generate by sending them price signals.

2.3.3 Efficient Energy Sources

The issue of efficient energy choices means that the fuel resources will go further in the long-run. When the incremental costs of acquiring that energy can be spread among greater number of energy users, competitive pricing and energy efficiency can co-exist. Adding new energy loads that are based on high efficiency technologies helps to minimize incremental infrastructure costs for both natural gas and electrical delivery systems.

Figure 2-17 below compares the efficiency of using natural gas to generate electricity, which is then used in the home, to the efficiency of supplying natural gas directly to the home for the same end use. These energy sources can be compared in this way, since existing hydro generating facilities are operating essentially at supply capacity and therefore any new electricity load must rely on incremental supply generated at the margin. A substantial portion of marginal electricity supply, whether imported or produced in-Province, is generated using natural gas or other fossil fuels.

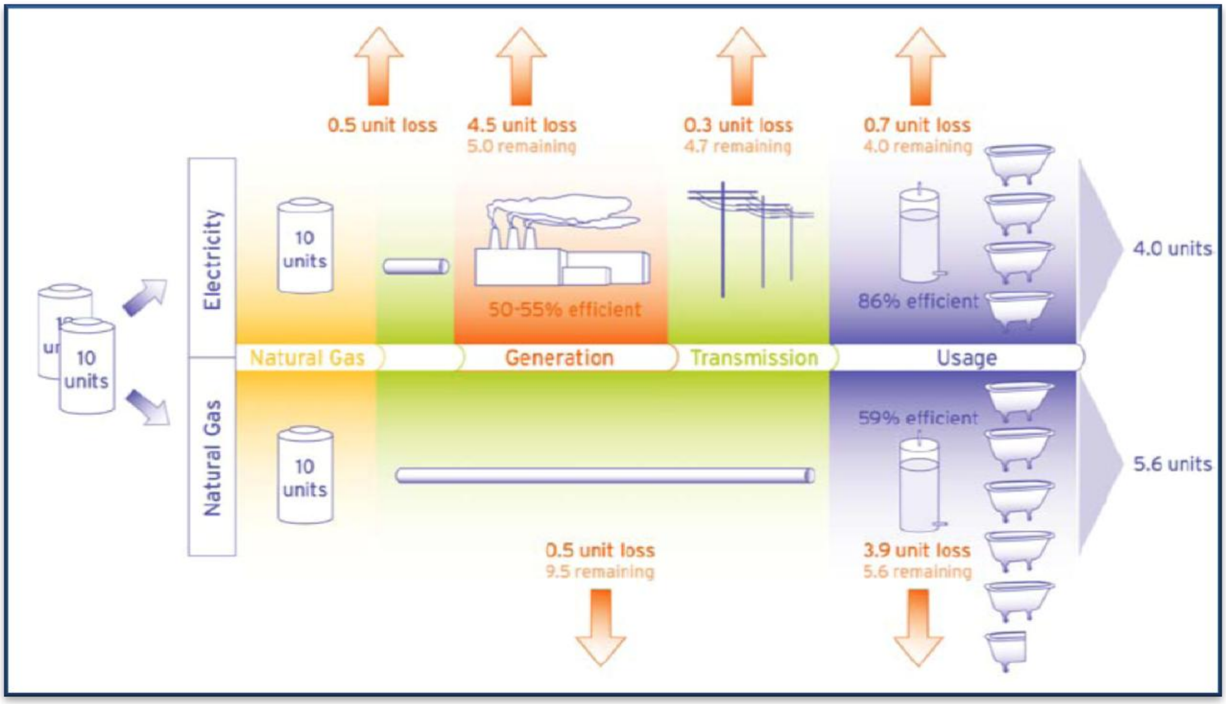
Figure 2-17: Natural Gas Efficiency for Home Heating



This demonstrates how the improved efficiency of using natural gas for home heating directly in the home can heat almost twice as many houses as would the same amount of natural gas used to generate electricity sufficient to heat homes. Alternatively, the same number of homes could be heated for almost twice as long using natural gas directly in the homes.

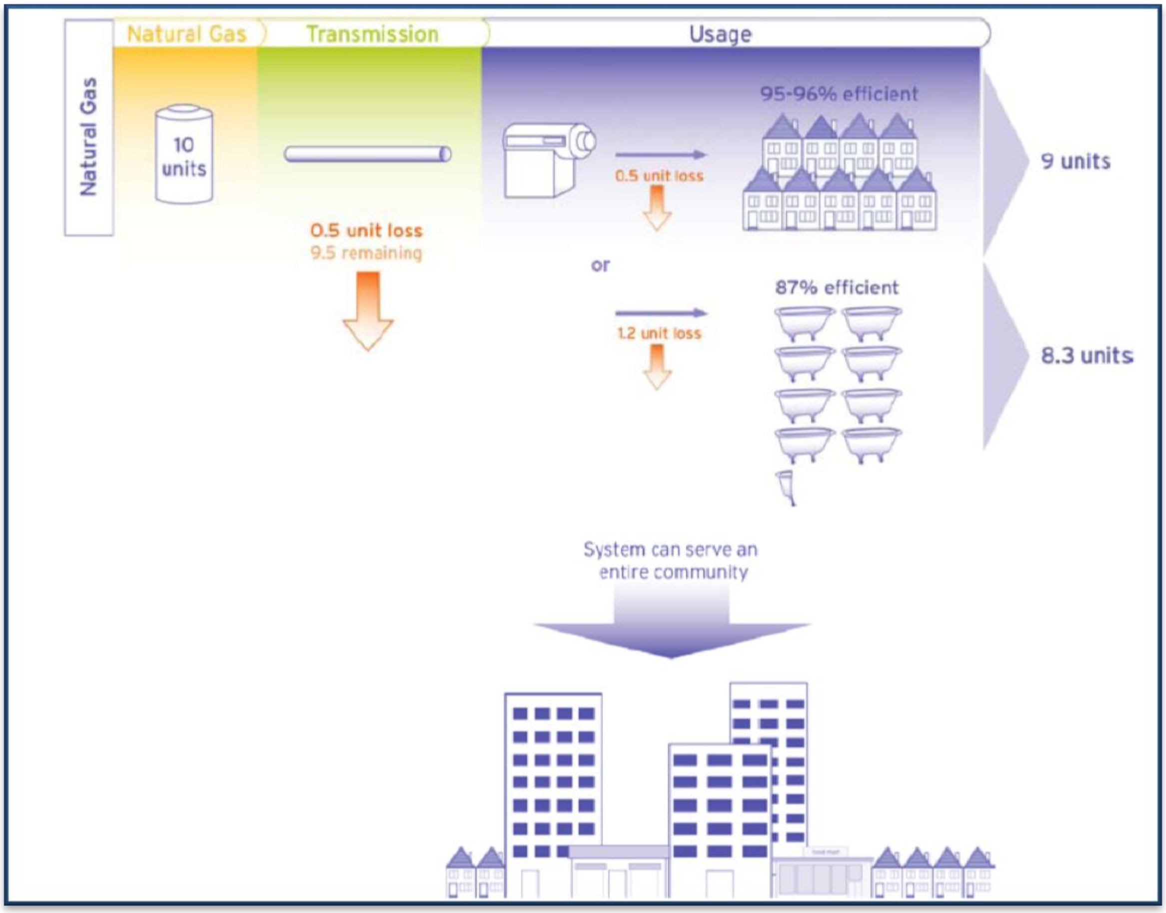
Similarly, as demonstrated in Figure 2-18, using natural gas directly in the home for domestic hot water has efficiency benefits over using gas to generate electricity and then delivering electricity to the home to heat the water.

Figure 2-18: Natural Gas Efficiency for Domestic Hot Water



Additionally, natural gas is an important and efficient part of energy system technology and integral to community energy planning. Use of natural gas in District Energy Systems, for example, can provide reliable and cost effective distribution of energy for space heating and hot water in multi-unit developments or even multi-use communities, at some of the highest possible efficiencies. Figure 2-19 illustrates the efficiencies that can be achieved with this type of system.

Figure 2-19: Natural Gas Efficiency for District Energy Systems



Thus, given that natural gas is an efficient energy source, it is important that it remains a viable solution and an important foundational fuel in meeting future energy needs. The FEU's New Initiatives ensure that natural gas is included as part of the solution.

2.3.4 Summary: Energy Environment in BC Challenges the Role of Natural Gas in the Energy Mix

Due to the large hydro generation base in BC, there is a belief that electricity represents the best low carbon choice to meet energy needs. However, BC's electricity grid is under cost increase pressures to meet the existing and projected load requirements, and thus any additional load requirements from non-traditional market segments from electricity could add to the problem[39]. The GHG emissions reduction targets have the potential to adversely change consumers' perception of natural gas over the long term. The targets will likely shift investment and consumption decisions of the consumer away from natural gas towards the consumption of

---

[39] BC Hydro's recent Revenue Requirement Application for 2012 to 2014 will be revised later this year and will see proposed rate increase to be reduced from 32 percent (initially estimated) to 16 percent over three years.

greener alternatives (i.e. electricity or other renewable energy alternatives such as solar or geothermal). This focus on renewable energy may supersede historical decision criteria such as cost of product, ease of use, and reliability, which is further discussed in the following Section.

2.4 CHANGING CUSTOMER EXPECTATIONS

Historically, customer energy choice and more specifically the perception of natural gas was driven by market factors such as price, accessibility, ease of use, and availability. In recent years, however, consumer perception of natural gas has changed as result of energy policy requirements to reduce GHG emissions, invest in demand side measures (or EEC), and produce and deliver energy from clean or renewable sources, as well as lower carbon energy sources and innovative energy technologies. The result of this change in perception is a move by customers toward "greener alternatives". This has led customers to shift investment and consumption decisions away from natural gas towards energy efficiency and the consumption of electricity and cleaner, lower carbon, and renewable energy sources (such as Biomethane, solar, geothermal, biomass). This greater choice for customers has created competitiveness in the utility energy sector that was not present as recently as the 1990s.

The FEU use the term "customer" or "consumer" in this Section to mean developers, engineers, architects, commercial and industrial customers, institutional customers and municipal and government stakeholders, and to a limited extent end use residential customers. This customer group represents those in the marketplace who are the key decision makers determining the type of energy a building or house will use. In the case of developers, engineers and architects, this group represents thousands of end use customers who purchase a home with the energy choice selected by the developer.

Greener alternatives are being embraced by environmentally conscious consumers and there is substantial demand from customers for the New Initiatives. The demand for these New Initiatives is demonstrated by contact with customers through sales and account management activities, stakeholder consultation, and a number of different studies, further discussed below.

2.4.1 Sales and Account Management Activities

As mentioned in Section 2.1.5, during the normal course of sales, account management activities, customer care, and community and government relations activities, our staff speak with existing and potential customers regarding their or their constituents requirements for use of thermal energy, use of natural gas, and the role of the FEU in providing energy for the Province. As noted in the beginning of Section 2, customers and consumers have become more sophisticated and knowledgeable regarding energy. As a result, during these discussions, more customers and stakeholders are looking for energy solutions that go beyond the use of natural gas. Customers and stakeholders have shared with our staff that they are looking for ways to not only reduce energy consumption but also reduce GHG emissions. They indicate that they are considering using geo-thermal exchange, biogas, biomass, waste heat recovery, district energy systems, solar and combined heat and energy systems in meeting their energy needs.

Depending upon the end use customer desires (for example a developer will make a decision based upon the market in which they will sell their housing product) natural gas may not be seen as progressive enough. From a sales standpoint, this can often mean losing the opportunity to service the customer with natural gas as the customer's final decision would often be to go with a different thermal energy source supplemented with electricity.

It is in the interests of natural gas customers of the FEU that we are able to offer a suite of New Initiatives. By being able to do so, the FEU is able to provide customers with the best possible thermal energy solution as opposed to simply advocating only for natural gas. If the FEU are seen as only providing natural gas, the customer may not engage the FEU at all which will result in no gas going into a development, therefore affecting throughput levels on the natural gas system (as discussed in Section 2.1). If the customer engages the FEU, the FEU can develop a solution that may include natural gas but also other thermal energy options. This ensures that natural gas remains a viable solution.

2.4.2 Stakeholder Consultation

Stakeholder consultation has been a critical component in laying the foundation for New Initiatives. The FEU are involved in formal stakeholder consultation through its regulatory proceedings, as well as long-term resource planning and EEC efforts. The FEU 's stakeholder groups, comprised of customer organizations, government agencies and municipalities, industry, trades, manufacturers, NGOs, advocacy groups, other utilities, and First Nations ensure value creation and alignment with the market. The FEU have informed stakeholders of its involvement in the New Initiatives on several occasions. Stakeholders and customers have been very supportive of this change in direction for the company. In fact, there are very few customers and stakeholders with whom we have spoken that react negatively to the FEU providing New Initiatives. Customers and stakeholders have not indicated any confusion or concern as to why a gas utility is proposing to offer such services but rather see this as a logical move given the changing energy environment.

The FEU have had ongoing workshops with key stakeholders through its Long Term Resource Plan proceeding. In each of these workshops, the FEU have highlighted the changing energy environment, the challenges we face, and the pursuit of our New Initiatives in order to address the energy challenges.

The FEU's recognized the need for accountability in the EEC Application and proposed to form and engage an EEC Stakeholder Group (see Section 7 for further details). The objectives of the EEC Stakeholder Group are to guide and provide input on EEC activity. Appendix B includes the FEU's initial EEC Stakeholder Group invitation sent to various stakeholders in the Province, including members of Energy Service Companies ("ESCOs"), and the current list of EEC Stakeholder Group Members. In March 2010, the FEU had a presentation on Alternative Energy Solutions and Innovative Technologies (including NGV). In November 2010, the FEU also provided a separate presentation on the NGV application. In March 2011, the FEU asked those that supported the NGV application to write a letter to the Commission.

Members of the EEC Stakeholder Group and customer groups have provided letters supporting the FEU's position to proceed with cost-effective EEC funding for NGV. These included:

- BC Apartment Owners & Managers Association
- BC Sustainable Energy Association ("BCSEA")
- City of Vancouver
- Commercial Energy Consumers Association of BC ("CEC")
- Fraser Basin Council

In addition, the BC government, BCSEA and CEC all supported NGV EEC as being in the public interest[40].

Furthermore, the FEU consulted a number of stakeholders regarding interest in pursuing the development of the Biomethane service offering and received letters of support from the following stakeholders:

- BC Agricultural Research & Development Corporation
- BC Bioenergy Network
- BC Sustainable Energy Association
- Bullfrog Power
- Central Heat Distribution Limited
- City of Abbotsford
- Columbia Shuswap Regional District
- David Suzuki Foundation
- Pacific Carbon Trust

Please see Appendix B for copies of these letters of support for both Biomethane Service and NGV Service.

2.4.3 Alternative Energy Surveys

The Alternative Energy Survey was first conducted in 2009 to assess British Columbians' awareness, knowledge, and attitudes towards alternative energy technologies. The surveys are comprised of two key parts: a qualitative phase involving a series of in-depth interviews with key influencers of energy decisions in British Columbia, and a quantitative omnibus study to measure awareness and adoption of alternative energy options among the general BC

40 See NGV EEC Incentive Reply Argument Submissions, included in Appendix E.

population. The 2009 survey was conducted by two companies: TNS Canadian Facts provided the in-depth qualitative component while Angus Reid Strategies conducted the omnibus portion. In 2010, TNS Canadian Facts undertook both parts of the survey to provide a holistic view on alternative energy.

The objective of the Alternative Energy Surveys was to:

- Explore British Columbians' awareness of alternative energy options, and their knowledge of these technologies;
- Assess the public's willingness to adopt alternative energy technology, and associated with this, their willingness to pay for them; and
- Determine the role of the FEU in providing energy derived from alternative energy sources.

In 2009 and 2010, a total of 802 and 800 interviews were conducted with a random sample of BC's population. The 2010 survey mirrored the 2009 version in terms of sample size, weighting, methodology, and survey instrument.

The results indicated that while BC residents' awareness and knowledge of alternative energy sources decreased somewhat in 2010 when compared to 2009, they continue to strongly favour incorporating alternative energy sources into new homes. However, fewer are willing to pay more for a home that uses these alternative energy sources when compared to 2009. This is probably due to the increasing cost of new homes, especially in the Lower Mainland, and concerns about affordability. Residents indicated that they see a role for the FEU in providing alternative energy options. In 2010, 51 percent of BC residents believe the FEU should offer alternative energy sources, up from 33 percent in 2009.

Customers indicated that the FEU have the financial resources, expertise and track record to assume a central role in the TES market. They indicated that the key drivers to adoption of these systems in the market are cost savings (particularly in case of geothermal heating and solar power) and also positive reputation and image in promoting greener buildings.

Please see Appendix C for a copy of both quantitative and qualitative Alternative Energy Surveys.

2.4.4 Biogas Market Study

In 2010, TNS was commissioned to help the FEU better understand the potential residential and commercial markets for biomethane, its market drivers, and sensitivities to different price points for a biomethane program.

The study focused on BC residential households and the FEU's commercial customers. A quantitative research methodology was used for both market segments. Similar questionnaires were developed for residential and commercial segments to ensure findings were comparable. The residential survey consisted of a total of 1,401 online surveys and the commercial survey consisted of a total of 500 online surveys.

Three different types of residential households were sampled:

- FEI customers (those who receive a gas bill directly from FEI – 799 interviews);
- Indirect customers (gas users who are not billed directly i.e. gas costs are included in strata fees or rent - 200 interviews); and
- Non-gas users (those who do not use gas - 50 interviews).

Approximately two-thirds of residents indicated that they support the FEU if the company opts to invest in biogas projects and an equal number feel that the FEU should offer a biogas program for customers. The results indicated that if all factors remained constant (e.g., energy prices remain unchanged), 56 percent of FEI's residential customers and 47 percent of commercial customers would commit to a biogas program on the benefits of the fuel alone. Providing for future generations, preserving nature, and "doing the right thing" were among the most common reasons provided by those who said they would potentially enrol in the program.

Please see Appendix C for a copy of the Biogas Market Study.

2.4.5 Residential Customer Satisfaction Research

In 2010, the FEU adopted an additional customer satisfaction and commitment model. For the first time, benchmarks have been established to compare the FEU's customer satisfaction levels with those of other utilities in Canada.

The research results answered the following research questions:

- How satisfied are residential customers with the FEU's services overall? And how does this level of satisfaction compare against other (1) natural gas companies, and (2) local utilities?
- How committed are customers to the FEU?
- How did the FEU perform on various aspects of its services?
- What can the FEU do to increase customer satisfaction?

A total of 1,291 residential customers were interviewed in two waves of telephone interviewing. In addition to interviews with our customers, results from a survey of 2,000 random Canadians were included in this study to compile benchmark information.

Compared to other major natural gas utilities in Canada, the FEU's satisfaction levels were around the market average. The results indicated that residential customers required the FEU to offer rebate incentives for energy efficiency upgrades in order to increase customer satisfaction.

Please see Appendix C for a copy of the Residential Customer Satisfaction Research.

2.4.6 Summary: Customers Interested in the FEU Offering "Greener Alternatives"

The FEU has responded to customer interest in greener alternatives through the New Initiatives. We believe natural gas continues to have a role in the long term sustainability picture due to the advantages inherent in its physical properties, i.e. it has the lowest emissions of the fossil fuels, no/low particulate matter, etc. and should therefore be encouraged, as the "right fuel for the right application, at the right time".

2.5 CONCLUSION: THE FEU'S ROLE IN ADDRESSING DRIVERS FOR NEW INITIATIVES

The FEU is in a good position to offer greener alternatives in response to declining throughput levels, government energy objectives, environmental policy and legislation, the energy production and consumption environment in BC, and customer expectations and demand.

Table 2-9 below summarizes how the FEU's New Initiatives respond to the changing energy environment. Each of the New Initiatives are further discussed in greater detail in the following Sections below.

Table 2-9: The FEU's New Initiatives Respond to the Changing Business Environment

The FEU's New Initiatives	Drivers For New Initiatives: Declining Throughput levels	BC's Energy Objectives and Other Related Policies and Legislation	Energy Environment in BC	Changing Customer Expectations
Biomethane Service	• Use of existing natural gas infrastructure	• Meet BC's energy objectives as set in the *CEA* (and the *UCA*) • Aligned with BC Energy Plan	• Reduce GHG emissions in residential and commercial sectors	• Aligned with customers and stakeholders interest and demand for greener alternatives
Natural Gas Vehicles Service	• Add load to the natural gas system	• Meet BC's energy objectives as set in the *CEA* (and the *UCA*) • Aligned with BC Energy Plan	• Reduce GHG emissions in transportation sector	• Aligned with customers and stakeholders interest and demand for greener alternatives
Thermal Energy Systems Service	• Use of existing natural gas infrastructure • Add load to the natural gas system	• Meet BC's energy objectives as set in the *CEA* (and the *UCA*) • Aligned with BC Energy Plan	• Reduce GHG emissions in residential and commercial sectors, as well as industrial sectors	• Aligned with customers and stakeholders interest and demand for greener alternatives
Energy Efficiency and Conservation	• In general EEC contributes to declining throughput levels, however, making such initiatives available may also help to retain the customers	• Meet BC's energy objectives as set in the *CEA* (and the *UCA*) • Aligned with BC Energy Plan • In compliance with DSM Regulation	• Reduce GHG emissions in the Province • Reduce energy costs for customers	• Aligned with customers and stakeholders interest and demand for greener alternatives

3 OVERVIEW OF LEGAL FRAMEWORK APPLICABLE TO NEW INITIATIVES

This Section is a submission of FEU's legal counsel that outlines key aspects of the general legal framework that governs the regulation of the New Initiatives to provide context for the evidence in this Submission. It is not intended to be exhaustive, and the FEU will make further detailed legal submissions in the argument phase of this Inquiry. The FEU submit that the most efficient means of dealing with any legal questions is to defer them to final argument, rather than include them as information requests.

This Section is organized as follows:

- Section 3.1 discusses public interest assessments;
- Section 3.2 discusses just and reasonable rates;
- Section 3.3 discusses the definition of "public utility" in the *Utilities Commission Act*; and
- Section 3.4 discusses how the *Act* expressly contemplates a public utility offering different classes of service.

3.1 THE NEW INITIATIVES AND PUBLIC INTEREST ASSESSMENT

There are four sections of the *UCA* that can give rise to a public interest assessment in the context of developing New Initiatives: section 44.1 (long term resource plans), section 44.2 (expenditure schedules), section 45 (CPCNs), and section 71 (energy supply contracts). Sections 44.1, 44.2, and 71 require the Commission to determine whether a Long Term Resource Plan ("LTRP"), expenditure schedule or energy supply contract is in the "public interest", with specific regard to the enumerated factors in sections 44.1(8), 44.2(5), and 71(2.1) (discussed below). Section 45 is similar, except that it uses the phrase "public convenience and necessity" in place of "public interest"; the jurisprudence generally treats this test as similar to, if not the same as, a public interest assessment.

The specific criteria that the Commission must consider under a section 44.1, LTRP assessment are set out in subsection 44.1(8) as follows:

> *(a) the applicable of British Columbia's energy objectives,*
>
> *(b) the extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the Clean Energy Act,*
>
> *(c) whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures, and*

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

The specific criteria the Commission must consider under a section 44.2 expenditure assessment are set out in subsection 44.2(5) as follows:

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

(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 schedule 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.

The specific criteria the Commission must consider in a CPCN application are set out in section 46(3.1) as follows:

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

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any, and

(c) the extent to which the application for the certificate is consistent with the applicable requirements under sections 6 and 19 of the Clean Energy Act

The specific criteria the Commission must consider in a section 71 application are set out in section 71(2.1) as follows:

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

(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 energy supply contract is consistent with the applicable requirements under sections 6 and 19 of the Clean Energy Act,

> *(d) the interests of persons in British Columbia who receive or may receive service from the public utility,*
>
> *(e) the quantity of the energy to be supplied under the contract,*
>
> *(f) the availability of supplies of the energy referred to in paragraph (e),*
>
> *(g) the price and availability of any other form of energy that could be used instead of the energy referred to in paragraph (e), and*
>
> *(h) in the case only of an energy supply contract that is entered into by a public utility, the price of the energy referred to in paragraph (e).*

Although the *UCA* specifies these specific criteria for each of the public interest assessments, the test for assessing the public interest as developed in Canadian jurisprudence is otherwise left in tact by these provisions. The test for whether the public interest (or public convenience and necessity) has been met, as set out in the case law, is a flexible one that does not admit a precise definition. Whether either test has been met involves the formulation of an opinion by the Commission, and in either case, that opinion must be based on facts established through evidence placed before the Commission. Generally speaking, a consideration of the public interest requires the weighing of competing interests of all the affected members of the public and any legislated considerations in arriving at an opinion of whether a given project is in the public interest (or is required by the public convenience and necessity). It is a matter of discretion as to how much weight the regulator gives to any one consideration, impact, or concern of the public. The test allows the regulator to weigh both private and public interests in arriving at its opinion[41].

While each of the New Initiatives engage unique considerations, and each investment within these categories will engage unique considerations based on their specific circumstances, there are factors that are common to all of the New Initiatives and will likely be engaged by the consideration of any such project. For instance, the New Initiatives promote "British Columbia's energy objectives", were introduced in response to customer demand, and promote the efficient use of the natural gas infrastructure. The FEU discuss these factors, and others, in subsequent sections of this Submission.

3.2 JUST AND REASONABLE RATES: COST RECOVERY AND RATE DESIGN

Rate setting under sections 59-61 of the *Act* is concerned with recovery of costs, and allocating risks and rewards associated with investments, including those investments that the Commission has previously reviewed under sections 44.2 and 45 and has determined are in the

[41] Cases that describe this test include *Memorial Gardens Association (Canada Ltd.) v. Colwood Cemetary Co.*, [1958] S.C.R. 353 and *Tsawwassen Residents Against Higher Voltage Overhead Lines Society v. British Columbia*, 2006 BCCA 537.

public interest. The principle of just and reasonable rates comes into play with all of the New Initiatives, which require investments that must be recovered from, and allocated appropriately among, the FEU's customers.

Section 60(1) of the *UCA* states that in setting a rate, the Commission "must consider all matters that it considers proper and relevant affecting the rate", and "must have due regard to the setting of a rate that (i) is not unjust or unreasonable within the meaning of section 59". In order to be "just and reasonable" a rate must therefore meet the criteria set out in section 59(5) of the *UCA*, which provides:

> *(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,*
>
> *(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.*

In the Commission's ROE Decision of the FEU's 2009 ROE and Capital Structure Application, it described this framework as follows:

> *"The Commission's mandate is to ensure that ratepayers receive safe, reliable and non-discriminatory energy services at fair rates from the public utilities it regulates, and that shareholders of those public utilities are afforded a reasonable opportunity to earn a fair return on their invested capital. The process to establish a fair return and just and reasonable rates is enshrined in the UCA where "the commission must consider all matters that it considers proper and relevant affecting the rate" and in doing so it must have due regard to the setting of a rate that "is not unjust or unreasonable" within the meaning of section 59 (of the Act)."*

A cornerstone of just and reasonable rates is the recovery of prudently incurred costs. A prior finding that expenditures are in the public interest (or public interest and necessity) generally means that the decision to undertake the expenditure was prudent, although the execution of the project is still subject to review for prudence. Provided the execution was prudent, the expenditure is a legitimate utility cost of service and is recoverable from customers. This would be true in the case of each of the New Initiatives.

The question of which specific customers groups pay for a class of service (and how costs are allocated among different classes of service) is a matter of rate design, and it is also addressed under section 59-61 of the *UCA*. Rate design is concerned with balancing the risk, and allocating the rewards, associated with investments. Biomethane Service, CNG/LNG Service, and TES all give rise to rate design considerations, and the Commission has already approved rate constructs for all three of the New Initiatives that are discussed later in this Submission.

3.3 THE DEFINITION OF "PUBLIC UTILITY" IN THE *UCA*

The *UCA* dictates what services are regulated through the definition of "public utility" in section 1 of the *Act*. The various regulatory provisions set out in Part 3 of the *Act* incorporate the definition of "public utility", and provide the Commission with its jurisdiction to oversee the activities of public utilities. The definition of "public utility" must be interpreted according to the legal rules of statutory interpretation, which require the Commission to give effect to the plain and unambiguous meaning of the words found in the definition. The *UCA* confers no discretion upon the Commission to decide, as a matter of regulatory policy, that certain entities, who otherwise meet the definition, are not subject to the *UCA*[42]. In the case of Biomethane, NGV, TES, and EEC, the Commission has previously recognized, either expressly or implicitly, in various decisions that persons who provide these services meet the definition of "public utility". The FEU submit that all stakeholders would benefit from an explicit Commission determination on these matters as part of this Inquiry.

The definition of "public utility" set out in section 1 of the *UCA* is as follows:

> *"public utility" means a person, or the person's lessee, trustee, receiver or liquidator, who <u>owns or operates</u> in British Columbia, <u>equipment or facilities</u> for*
>
> *(a) the production, generation, storage, transmission, sale, delivery or provision of electricity, natural gas, <u>steam or any other agent for the production of</u> light, <u>heat</u>, cold or power <u>to or for the public or a corporation for compensation</u>, or*
>
> *(b) the conveyance or transmission of information, messages or communications by guided or unguided electromagnetic waves, including systems of cable, microwave, optical fibre or radiocommunications if that service is offered to the public for compensation,*
>
> *but does not include*
>
> *(c) a municipality or regional district in respect of services provided by the municipality or regional district within its own boundaries,*

[42] There are only two provisions of the *Act* that allow for the exemption of persons from regulation under the provisions of the *Act*: section 22 provides that the minister, by regulation, may exempt certain persons from section 71 of the *Act*; and section 88 provides that with the advance approval of the Lieutenant Governor in Council, the Commission may except a person, equipment or facilities from the application of all or any of the provisions of the Act.

> *(d) a person not otherwise a public utility who provides the service or commodity only to the person or the person's employees or tenants, if the service or commodity is not resold to or used by others,*
>
> *(e) a person not otherwise a public utility who is engaged in the petroleum industry or in the wellhead production of oil, natural gas or other natural petroleum substances,*
>
> *(f) a person not otherwise a public utility who is engaged in the production of a geothermal resource, as defined in the Geothermal Resources Act, or*
>
> *(g) a person, other than the authority, who enters into or is created by, under or in furtherance of an agreement designated under section 12 (9) of the Hydro and Power Authority Act, in respect of anything done, owned or operated under or in relation to that agreement; …* [Emphasis added.]

In the following Sections, the FEU discuss each of the constituent parts of this definition in the context of the issues raised in this Inquiry[43].

3.3.1 Requirement 1: "owns or operates… equipment or facilities…"

For a person[44] to be regulated as a "public utility" under the *UCA* the person must own or operate equipment or facilities in British Columbia. There are two key points to take from this requirement. First, either ownership or operation of the "equipment or facilities" will meet this first requirement; there is no requirement that an entity both own and operate the facilities. Second, operation connotes an ability to control the operations of the equipment or facilities. There are a number of service arrangements possible between an entity and a customer that fall short of the FEU controlling the equipment or facilities.

3.3.2 Requirement 2: "… for the production, generation, storage, transmission, sale delivery or provision of…"

The second requirement for a person to be a regulated "public utility" under the *UCA* is that the "*equipment or facilities*" be used by the person for one or more of the following functions: "*the production, generation, storage, transmission, sale, delivery or provision of*…" the enumerated energy forms. These functions are very broad and encompass all aspects of the supply and delivery chain of an energy source. The *UCA* relies on the express exclusions set out in the

---

43 FEU does not discuss subsection (b) of the definition as it addresses telecommunication services which are not relevant to this Inquiry.

44 A "person" is defined in the *Interpretation Act*, R.S.B.C. 1996, c. 238, as including "a person, partnership or party and the personal or other legal representatives of person to whom the context can apply according to law. The definition of "public utility" extends that definition to include a person's lessee, trustee, receiver or liquidator.

definition of “public utility” (i.e. subsections (c) through (g)) to exclude certain portions of the supply and delivery chain from regulation by the Commission.

3.3.3 Requirement 3: “… electricity, natural gas, steam or any other agent for the production of light, heat, cold or power…”

The third requirement specifies the types of energy forms to which public utility regulation under the *UCA* extends. The *UCA* extends public utility regulation not only to electricity and natural gas, but also to steam and “any other agent for the production of light, heat, cold or power”. In terms of the services at issue in this Inquiry:

- the provision of Biomethane service is encompassed within the term “any other agent for the production of…heat”;
- the provision of natural gas for NGV is encompassed within the term “natural gas”;
- the provision of steam is encompassed within “steam”; and
- the provision of geothermal energy, solar thermal energy, biomass or other sources is encompassed within “any other agent for the production of light, heat, cold or power”.

3.3.4 Requirement 4: “… to or for the public or a corporation…”

The fourth requirement is that the person provides the energy “to or for the public or a corporation”. The “public” is not defined, but it is reasonable to conclude from the context that the definition distinguishes between self-provision of energy and provision of energy to third parties. This is evident from the fact that provision to only one corporation is sufficient to meet this requirement. Also, from a policy perspective, the distinction between self-provision and provision to third parties makes sense because third parties will tend to have limited practical recourse against a provider of energy for light, heat, cold or power, and thus require the protection inherent in regulation. Thus, the FEU submit that the provision to any third party is sufficient to constitute provision to “the public”.

The provision of the listed energy forms to a “corporation” will also meet this requirement. A corporation is a legal entity, and it includes a strata corporation. The *Interpretation Act* defines "corporation" to mean “an incorporated association, company, society, municipality or other incorporated body, where and however incorporated, and includes a corporation sole other than Her Majesty or the Lieutenant Governor”. Thus, the delivery of one of the listed energy forms to a single strata corporation will meet this requirement.

3.3.5 Requirement 5: “for compensation”

The fifth requirement is that the entity providing one of the listed energy forms to the public or a corporation must be receiving compensation in exchange for the service.

"Compensation" is a defined term in the *UCA*, and includes a wide range of forms:

> ***"compensation"*** *means a rate, remuneration, gain or reward of any kind paid, payable, promised, demanded, received or expected, directly or indirectly, and includes a promise or undertaking by a public utility to provide service as consideration for, or as part of, a proposal or contract to dispose of land or any interest in it;*

Charging a rate for service falls within the plain wording of this definition.

3.3.6 Does Not Include Municipal Utilities

Subparagraph (c) of the definition of "public utility" expressly excludes municipal utilities that would otherwise meet the test in paragraph (a) of the definition. The FEU's (or third party) investment in the assets precludes the application of this exclusion.

3.3.7 Does Not Include Provision to Employees or Tenants

Subparagraph (d) of the definition of "public utility" expressly excludes self-provision of the listed energy forms, and provision to employees or tenants.

"Tenant" is not affirmatively defined in the *UCA*, but the *Act* does state that a "tenant" does not include a lessee for a term of more than 5 years. The term should be given its usual meaning. A tenant is, in common parlance, a party that has a rental or leasehold interest with a landlord. In the context of the *UCA*, a tenant would otherwise be part of the public. The purpose of defining "tenant" to exclude lessees for terms longer than five years is to limit the ability for entities that would otherwise be subject to regulation from entering into long-term leases with third parties so as to fit within this paragraph (d) exclusion.

Consequently, an owner of an apartment building that provides heat to its rental units will not be treated as a "public utility" in its provision of heat to rental units if the leases signed are less than 5 years in term. An owner of an apartment building that provides heat to its rental units will be treated as a "public utility" in its provision of heat to rental units if the leases signed are more than 5 years in term.

3.3.8 Does Not Include "Petroleum Industry or [a person] in the wellhead production of oil, natural gas or other natural petroleum substances"

Subparagraph (e) of the definition of "public utility" expressly excludes persons "not otherwise a public utility" that are engaged in the "petroleum industry or in the wellhead production of oil, natural gas or other natural petroleum substances".

"Petroleum industry" is a defined term in section 1 and includes "the retail distribution of liquefied or compressed natural gas". In other words, CNG/LNG Service is not regulated unless it is provided by an entity that is "otherwise a public utility". That would include the FEU. The Commission confirmed this interpretation in the recent NGV Decision[45].

3.3.9 Does Not Include "production of a geothermal resource, as defined in the Geothermal Resources Act"

Subparagraph (f) of the definition of "public utility" expressly excludes persons who are not otherwise public utilities and who are engaged in the production of a geothermal resource, as defined in the *Geothermal Resources Act* ("*GRA*").

The definition of "geothermal resource" in the *GRA* is:

> *… the natural heat of the earth and all substances that derive an added value from it, including steam, water and water vapour heated by the natural heat of the earth and all substances dissolved in the steam, water or vapour obtained from a well, but does not include*
>
> *(a) water that has a temperature less than 80º C at the point where it reaches the surface, or*
>
> *(b) hydrocarbons.*

Section 1(4) of the *GRA* provides: "If there is inconsistency between the *Utilities Commission Act* or *Water Act* and this Act, the *Utilities Commission Act* or *Water Act* prevails." Subsection (f) of the definition of "public utility", which relates to geothermal resources, does not apply so as to exempt the FEU from the application of the *UCA* and bring it within the ambit of the *GRA* because the temperature of the water at the surface will be less than 80º C and is therefore not a "geothermal resource". As noted above, the definition of "geothermal resource" excludes water that has a temperature less than 80º C at the point where it reaches the surface.

3.3.10 Does Not Include Persons Who Enter Into Support Services Agreements with BC Hydro

Subparagraph (g) of the definition of "public utility" expressly excludes persons, other than BC Hydro, who enter into or are created by, under or in furtherance of an agreement designated under section 12 (9) of the *Hydro and Power Authority Act*. This exception is of no application here.

45 Order No. G-128-11, dated July 19, 2011 (page 18-19), included in Appendix H.

3.4 CLASSES OF SERVICE

One other important element of the legal framework is that the *UCA* expressly contemplates a single utility having different classes of service. This is evident from a review of section 60 of the *Act*:

> *60(1) In setting a rate under this Act*
>
> *…*
>
> *(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 a rate for each unit that it considers to be just and reasonable for that unit, without regard for the rates fixed for any other unit.*

The import of this provision is that the *Act* expressly contemplates a public utility such as FEI providing, for example, both natural gas service and thermal energy services within the same regulated utility. Not only does the *Act* contemplate this scenario, but it dictates the manner in which rates are to be set so that the customers of one class of service do not cross-subsidize customers of another class.

In terms of the New Initiatives, Biomethane Service, NGV Service, and EEC programs are all part of the natural gas class of service, while TES Service is a different class of service within FEI.

4 FLEXIBLE OWNERSHIP MODEL FOR BIOMETHANE UGRADING ASSETS

The FEU identified the development of Biomethane in the 2008 Long Term Resource Plan as an opportunity to meet customer interest in low carbon fuels, reduce GHG emissions, increase energy efficiency and to complement the use of natural gas and its infrastructure. FEI filed a Biomethane Application on June 8, 2010. On December 14, 2010, the Commission released the Biomethane Decision[46], which granted approval to allow FEI to proceed with the program on a test basis for a two-year period. The two-year period contemplated in the Biomethane Decision will end on December 14, 2012. FEI's progress in developing Biomethane upgrading and recovery projects and in rolling-out the Biomethane Service to customers is described in the Biomethane Report filed with the 2012-2013 RRA. FEI has made good progress thus far, but more time is needed to assess and develop the model for Biomethane going forward. The post-implementation review directed in the Biomethane Decision should proceed on the timeline set out in that order.

A number of the issues that are set out in the scope of this Inquiry, as they would pertain to Biomethane – in particular those that are directed to whether FEI should engage in Biomethane activities as a regulated utility, allocation methodology for Biomethane costs to customers, competition, and evaluation of approved regulated Biomethane initiatives – are best addressed as part of the post-implementation review once the two-year test period is completed. However, one of the outstanding issues from the Biomethane proceeding can and should be addressed at this time: the issue of ownership of the upgrading assets for converting raw biogas into Biomethane. In this Section, the FEU address the legal and policy considerations that favour the FEU retaining the flexibility to own upgrading assets. The FEU believe that by retaining this flexibility, the FEU will be able to encourage new supply resources in tandem with established demand where those supply resources might otherwise not be available. Customers will ultimately benefit from a ready supply of Biomethane to meet established demand, and this also serves British Columbia's energy objectives.

This Section is organized as follows:

- Section 4.1 summarizes the approved Biomethane initiative;
- Section 4.2 provides a high level summary of the FEU's progress in developing Biomethane supply and in rolling-out the Biomethane offering to customers;
- Section 4.3 explains why it is in the public interest to allow the FEU to have the flexibility to own and operate biogas upgrading equipment where commercial circumstances dictate;

[46] Order No. G-194-10, dated December 14, 2010, included in Appendix H.

- Section 4.4 provides an overview of the business model employed in other jurisdictions, in comparison with the business model employed by the FEU; and
- Section 4.5 addresses proposed guidelines in respect of the ownership of upgrading equipment.

In support of this Section, the FEU have provided, in Appendix D, the relevant sections of the 2008 and 2010 LTRPs, FEI 2010-2011 RRA, the Biomethane Application, and IR responses from the Biomethane proceeding. For ease of reference, this Section provides a summary of the key parts of these previous filings as they relate to the issues identified by the Commission and FEU's proposed guidelines in Section 4.5 and Section 8 in response to those issues.

4.1 DESCRIPTION OF BIOMETHANE OFFERING AS APPROVED BY THE COMMISSION

The Biomethane Decision approved FEI's Biomethane Application, largely as filed, for a trial period of two years. This Section describes, for context, the nature of the Biomethane offering approved by the Commission.

The Biomethane offering outlined in the Biomethane Application involved both a supply component and a rate offering to customers on an optional basis. The FEI identified:

- two Biomethane supply models, with the primary difference being who owns and operates the equipment for upgrading raw biogas to Biomethane;
- two specific supply projects (one in Salmon Arm and one in Abbotsford), which illustrated the two supply models;
- a premium rate offering allowing for a notional sale of Biomethane to FEI customers who elect the service on a voluntary basis; and
- a cost allocation methodology to support recovery of Biomethane-related costs from those customers that choose to take the service, while some costs for the program are recovered from all customers.

FEI sought acceptance of an expenditure schedule under section 44.2 of the *UCA* for upgrading assets that it was proposing to own and operate for the Salmon Arm project. FEI sought approvals under sections 59 to 61 of the *UCA* for the Biomethane rate design.

As part of the public interest justification for the expenditure schedule, FEI explained that Biomethane is a renewable energy source, the production and consumption of which are considered carbon neutral as they do not result in additions to greenhouse gas emissions. The Commission accepted FEI's position that Biomethane upgrading was consistent with British Columbia's energy objectives:

> *"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."*[47]

The Commission established a two-year test period to confirm the customer demand for the service. During that time, the total production of Biomethane for all projects is limited to 250,000 GJ per year during the test period, and the Commission set a maximum price for the acquisition of Biomethane supply of $15.28 per GJ. These provisions allowed for an initial Biomethane supply to be developed, while ensuring that the supply obtained during the trial period would not outpace demand and would be cost effective for customers.

In the Biomethane Application, FEI had outlined the two supply models that fit within the business model for the Biomethane program. FEI's Biomethane Application described its preferred ownership structure for this program as follows:

- FEI's partner would retain ownership and control over the equipment which digests organic material to create raw Biogas, as well as those assets required to collect raw Biogas from proposed collection locations such as digesters, landfills or sewage facilities.
- FEI would own and control the interconnection facilities. FEI's ownership of interconnection facilities minimizes system risk. FEI will always have final control of gas quality for safety reasons. Delivery to customers will be immediately terminated when Biomethane does not meet FEI's quality standards.
- FEI would own and operate upgrading facilities that convert raw Biogas into useable Biomethane that can be injected into the natural gas distribution system.

In the Biomethane Decision, the Commission made no findings regarding FEI's future role in owning upgrading assets, preferring to defer that decision until a future date:

[47] Order No. G-194-10, dated December 14, 2010 (page 26-27), included in Appendix H.

> *"With respect to [FEI'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."* [48]

In the Biomethane Decision, the Commission stated that it expects that during the two-year test period FEI, "*will learn valuable lessons which can be applied to the development of a model which will sustain the Program over the long term*". FEI believes that, with the exception of the issue of who should own and operate biogas upgrading facilities, the appropriate time to review and assess the principles and guidelines for Biomethane Service is at the end of this two-year test period in the process contemplated by the Biomethane Decision. In the Biomethane Application, FEI laid out guiding principles for the program and they appear on page 74 of the Biomethane Application excerpt and included in Appendix D in this Submission. FEI believes that these guiding principles are still valid, but they should and will be reviewed at the end of the two-year test period.

4.2 CURRENT STATUS OF FEI'S BIOMETHANE SERVICE

In this Section, FEI describes how the Biomethane Service has been implemented since the Commission approval of the Biomethane Application. There has been progress in the development of Biomethane, but not to the point where we could deal with all of the issues that are slated to be addressed in the two-year test period.

4.2.1 Biomethane Service Offering Phase 1

Phase 1 of the Biomethane initiative approved by the Commission is the initial rollout of the programs to residential customers only. Phase 1 of the program commenced in June 2011. The objective of Phase 1 was to validate producer reliability and consumer interest. To achieve this, FEI has commenced, and will continue to introduce the program to customers through a variety of communication channels, which will continue through 2011. One of the reasons behind only offering this program to residential customers in Phase 1 was due to the transition to a new Customer Information System, which will be implemented January 1, 2012.

4.2.2 Discussions with Government Regarding Carbon Tax Treatment of Biomethane

Since the Biomethane Decision, FEI has held discussions with the provincial government that have resulted in the government tabling the *Budget Measures Implementation Act, 2011*, before the legislature, which will certify Biomethane as a carbon-neutral fuel under the *Carbon Tax Act*. The impact of this legislative change will be that consumption of Biomethane will not attract carbon tax, which is a benefit to those customers choosing to elect into the program. For those residential customers who elect to purchase Biomethane, they will receive a credit on their bill

---

[48] Order No. G-194-10, dated December 14, 2010 (page 2), included in Appendix H.

each month to offset their amount of carbon tax paid on the portion of Biomethane consumed in that month.

4.2.3 Customer Education

On March 7, 2011, FEI held a focus group session in Vancouver comprised of more than twenty diverse participants to gather feedback on several proposed communication concepts for the program. The results of this focus group helped tailor the messaging used in the customer education activities of Phase 1 of the product offering. The uptake and interest in Phase 1 of the program will be key to encouraging continued development of additional supply sources allowing for expansion of the program to other customer groups. FEI will continue with customer education activities to ensure customers are sufficiently educated and encourage them to act on enrolling in the program.

4.2.4 Supply Projects

The Catalyst project began injecting Biomethane into FEI's distribution system in September 2010 and by March 31, 2011 the project had delivered over 15,000 GJs. Catalyst is taking measures to reach minimum contract levels within the contractual start-up window and we have seen the production from this facility increase in recent months as Catalyst has gained experience with their operations. We expect the Catalyst to deliver 59,000 GJs by the end of 2011.

Commencement on the development of the Columbia Shuswap Regional District ("CSRD") project was delayed pending the Commission decision on the Biomethane Application and as a result the project is expected to be commissioned by the end of 2011. The CSRD project is expected to deliver 2,000 GJs by the end of 2011 and it is projected that delivery for the year 2012 will be 26,000 GJs.

FEI is currently evaluating other new Biomethane projects. The most likely prospects are projects with the City of Kelowna and Metro Vancouver at Annacis Island. The potential project in Kelowna would be a landfill based project that is expected to start at approximately at 50,000 GJ/year. The Annacis Island project would be an organic waste digester with expected starting volumes of 100,000 GJ/year.

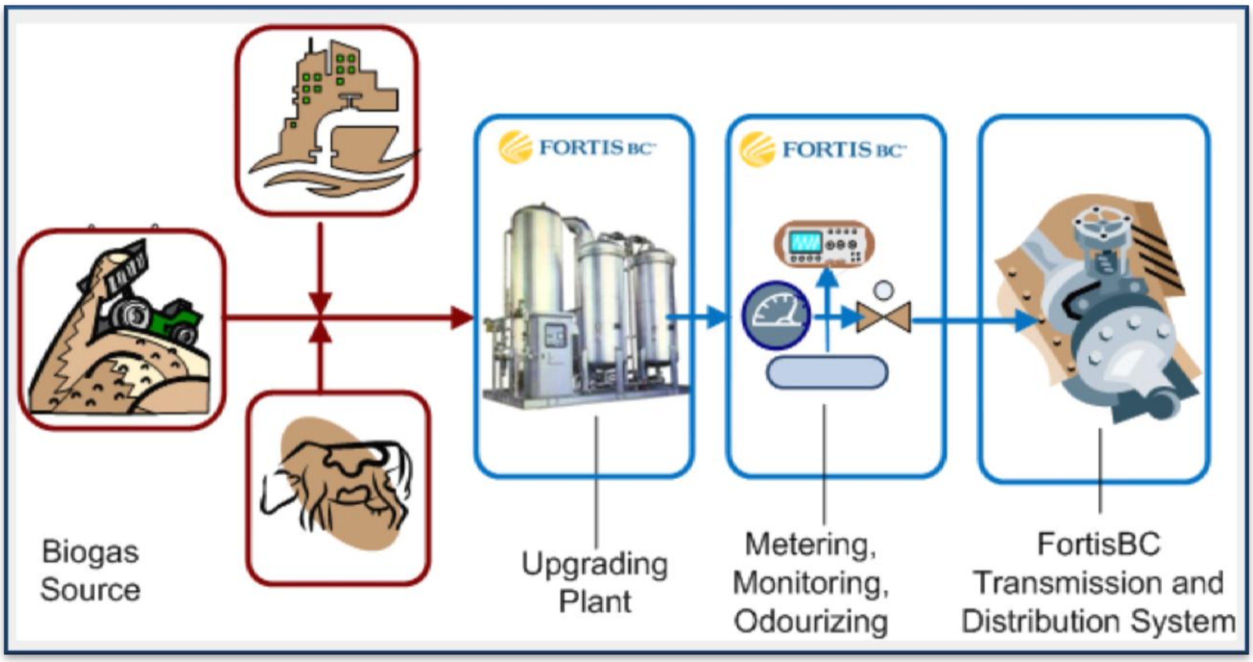
4.3 FEU SHOULD MAINTAIN FLEXIBILITY TO OWN AND OPERATE UPGRADING EQUIPMENT

As described in Section 4.1, an outstanding issue from the Biomethane Application proceeding was FEI's ownership model for upgrading assets, which contemplated FEI having flexibility to either own and operate the assets or have a competent third party own and operate them. In this Section, the FEU explain why their preferred ownership model is appropriate and in the public interest. The reasons in support of the preferred ownership model are the same as those articulated in the Biomethane Application proceeding, and what follows is primarily a review of those reasons. From a legal standpoint, the *UCA* dictates that upgrading facilities are regulated assets. There are several advantages associated with the FEU having the flexibility to own and operate the systems. Finally, it is beneficial for customers to have the facilities retained within the FEU themselves, and not segregated into a separate regulated entity under common ownership.

4.3.1 Ownership Model for Biomethane Upgrading

The primary difference between the two alternative models for bringing Biomethane supply on line is who owns and operates the upgrading equipment. The first ownership model is depicted in the graphic representation in Figure 4-1 below. The brown boxes depict what is owned by the third-party partner. The blue boxes depict FEU ownership.

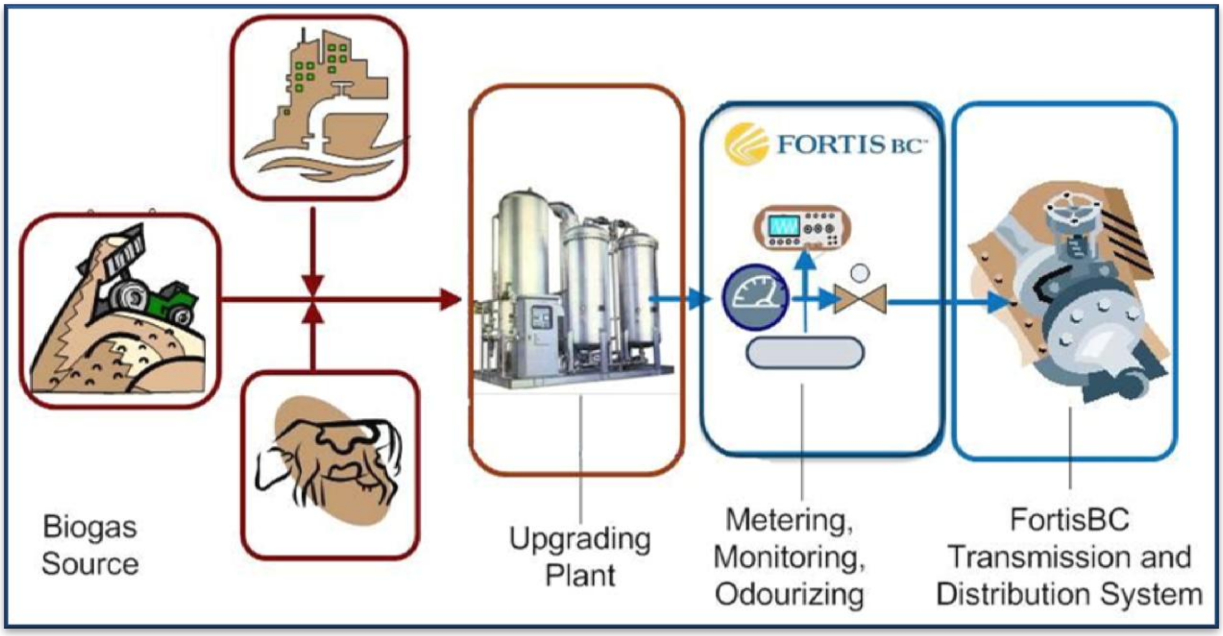
Figure 4-1: FEI's Role in Biomethane Projects



As indicated previously, in the preferred model the Biogas Source assets are owned by the project partner, not the FEU. The FEU must always, for safety and reliability purposes, own the Metering, Monitoring and Odourizing equipment. Only the upgrading ownership differs between the two models. Again, the brown boxes depict what is owned by the third party partner, while the blue boxes depict FEU ownership.

The alternative (partner ownership) model is depicted in Figure 4-2 below.

Figure 4-2: Exception to Ownership Structure



Regardless of the ownership model of the upgrading plant, the costs associated with owning and operating the upgrading plant get reflected in the commodity price for Biomethane. These costs are, in turn, recovered from natural gas customers who have opted into the Biomethane Service offering. The rationale for why it is important to offer two models of supply development given the early stage of development for this emerging industry is discussed later in Section 4.3.3.

4.3.2 Upgrading is a Regulated Public Utility Service

The threshold question in considering the FEU's role in owning and operating the upgrading plant is to determine whether owning and operating these facilities is a regulated activity under the *UCA*. The following are the key elements of the definition of "public utility" as they apply to owning and operating biogas upgrading equipment (these elements are discussed in further detail in Section 3). As Table 4-1 below demonstrates, owning and operating upgrading assets is a public utility service and therefore subject to the regulatory oversight set out in Part 3 of the *Act*. In the context of the FEU, the upgrading plant is part of the facilities used to provide a gas service (natural gas/biomethane blend) to customers.

Table 4-1: Owning and Operating Upgrading Assets is a Public Utility Service

Definition Of "Public Utility"	Definition Of Public Utility Applies To Owning And Operating Upgrading Assets
"owns or operates.. equipment or facilities"	This component of the definition of "public utility" is met by the FEU owning or operating biogas upgrading equipment. It is also met regardless of the identity of owner and operator.
"for the production, generation, storage, transmission, sale, delivery or provision of"	Biogas upgrading equipment is equipment that is used for the purpose of "generating" and "producing" Biomethane (out of raw biogas) for the delivery and sale of Biomethane (mixed with natural gas) to customers.
"electricity, natural gas, steam or any other agent for the production of light, heat, cold or power"	Biogas upgrading equipment is equipment that is used for the purpose of producing and generating an "agent" (Biomethane) for the production of heat and power.
"to or for the public or a corporation"/ "for compensation"	In the case where the FEU is the owner and operator of the upgrading assets, the Biomethane that is created by the biogas upgrading facilities is ultimately sold "to the public" through rates charged to the FEU's customers. In the case where a third party (i.e. any party other than the FEU) is the owner or operator of the upgrading assets and sells upgraded biomethane to the FEU, this aspect of the definition is met by virtue of the third party selling biomethane to the FEU, which is "a corporation".
"The Exceptions to the Definition"	None of the exceptions (see Section 3.3.6 to 3.3.10) to the definition of public utility apply in respect of biogas upgrading facilities owned and operated by the FEU or a third party.

Ownership and operation of biogas upgrading facilities falls within the definition of "public utility", and is therefore regulated under Part 3 of the *Act*.

By analogy, Independent Power Producers ("IPPs") that generate and sell electricity only to BC Hydro meet the definition of public utility, and require exemption orders from the Lieutenant Governor in Council to remove them from Commission regulation under Part 3 of the *UCA.*

As described further below, the Commission has also recognized that there are advantages to avoiding a proliferation of small regulated utilities within the FortisBC group of companies. In the following Section, the FEU explains why the flexible approach to ownership of the upgrading assets is in the public interest.

4.3.3 The Benefits of FEI's Approach to Ownership of Upgrading Facilities

There are several benefits to maintaining flexibility in terms of the ownership of upgrading facilities, which are discussed below.

The primary benefit of retaining flexibility is that it addresses concerns expressed by potential project proponents about owning and operating the facilities. As further explained in the Biomethane Application, FEI's approach to owning and operating upgrading equipment arose out of discussions about potential projects with the parties that would partner with FEI and who would own and operate the biogas source or digester. During these discussions, it became clear to FEI that potential developers had both financial and technical concerns regarding projects that involved upgrading equipment.

- The financial concern expressed by project partners was two-fold. First, potential developers indicated that it is typically easier to obtain financing when an experienced and reputable partner like FEI is involved in the upgrading process. Second, some potential developers indicated that they might not have access to enough capital to put both a raw biogas generating facility in place (such as a digester) and an upgrading facility. For example, both the City of Kelowna and the project developer for the Annacis Island project have indicated a preference to have FEI own the upgrade equipment based on access to capital.
- Their technical concerns arose from their lack of relevant experience. Developers indicated to FEI that having a partner with experience in gas processing, such as FEI, was attractive. Given the similarities between biogas upgrading and many of the functions and processes that FEI operates in its daily operations, FEI is a suitable partner for biogas developers who lack such expertise.

The financial and technical concerns articulated by potential developers suggested that the FEU could play a key role in ensuring that Biomethane supply was developed in British Columbia in a timely way. The FEU believe that, without FEI's involvement, some potential developers may be reluctant or incapable of bringing projects forward. By removing this impediment, the FEU facilitate the expansion of the Biomethane offering.

A second benefit from a flexible ownership structure is that owning and operating upgrading equipment gives FEI greater ability to respond to customer concerns and demands through an already existing distribution service system. FEI has an existing business and service infrastructure in place that can respond quickly to customer concerns and issues in the field.

Third, FEI is motivated to provide the best quality gas possible, while an independent operator may choose to reduce operating costs associated with upgrading by sacrificing maintenance, which could result in low-quality gas or reduced reliability. The fact that FEI will own the upgrading assets and use its expertise to operate them will enhance reliability of supply. FEI is motivated to provide the best quality gas possible as FEI answers directly to customers. FEI will be unable to meet customer expectations if it must continually reject Biomethane at the point of interconnection because it does not meet specifications. Accordingly, it is important that the upgrading process is controlled by an entity that has the means to ensure that the Biomethane produced meets specifications on a consistent basis and can be injected into the FEI distribution system. FEI has the expertise and competence to operate and maintain an upgrading plant.

Fourth, FEI can take advantage of existing resources by absorbing some of the additional work associated with a biogas plant without requiring additional staff, which will tend to improve the cost effectiveness of supply once a base level of resources is established. For example, in Salmon Arm, FEI intends to use existing staff to manage routine activities such as regular operating inspections, whereas a developer would need to hire staff specifically for this activity.

Ultimately, while FEI's ownership and operation of the upgrading facilities brings benefits, FEI will allow a variation of the model when project partners can meet the financial and technical standards required to own and operate upgrading equipment. In other words, in appropriate situations where the interests of customers and FEI are protected by the involvement of a qualified upgrading partner, FEI will not necessarily own and operate the upgrading equipment. The Catalyst project is a good example of a circumstance where the partner, Catalyst, was sufficiently sophisticated that their ownership of the upgrading plant would be unlikely to compromise the interests of FEI and its customers.

Further information on this topic can be found in the Biomethane Application Final Submissions included in Appendix D.

4.3.4 Modest Risk Associated with Owning and Operating Upgrading Equipment

From a customer perspective, it is important to ensure that flexibility and the other benefits referenced above are in proportion to any risks assumed by the FEU in securing additional Biomethane supply. In this Section, the FEU discuss the modest risks associated with FEI owning and operating upgrading equipment. The FEU believe that the benefits conferred by a flexible approach to the ownership of the upgrading plant outweigh the modest risks, supporting FEI's position that it is appropriate and in the public interest for FEI to own and operate this equipment.

There is limited cost or price risk on an upgrading plant. FEI's investment in the upgrading facilities is small compared to the cost of biogas collection facilities which is borne by the partners. The upgrading plant costs are based on a fixed price contract, which significantly reduces any cost risk associated with FEI's investment. FEI will include a 10 percent contingency in project costs, which is reasonable given that a large portion of the project cost is fixed (i.e. the upgrading plant). The operating costs are modest. They consist primarily of electricity costs, filter and media replacement, odorants and inspections. In sum, the cost risk is modest given the size of the required investment, and the FEU identified measures in the

Biomethane Application that will manage the risk appropriately. The excerpts from the Biomethane Application are included in Appendix D.

FEI believes that the risk of stranded assets associated with upgrading equipment is limited. FEI believes that there will be adequate demand for Biomethane as indicated by the research described in the Biomethane Application. Within 4 weeks of the launch of Phase 1, FEI had 200 customers signed up for the program. In addition, it is unlikely that stranded assets will result from discontinuance of Biogas supply. FEU's long-term raw Biogas supply contracts with the partners guarantee long-term supply of Biogas and a reasonable period over which to recover the equipment costs. In the event of discontinuance of raw biogas under FEI's contracts with partners, FEI's contracts will ensure that it has the right to enter the site and physically recover its facilities after a specified period of non-performance. The recovered equipment can then be used for other projects. The contracts can provide FEI with a termination payment to help offset the estimated value of the stranded assets and moving costs.

The risk of stranded assets through obsolescence is also limited. The current equipment recovers about 95 percent of the methane in biogas and any changes in technology over time will result in only minor efficiency improvements and would not make the current technology obsolete.

Thus, with limited risk associated with the FEU's ownership of upgrading facilities, the flexible approach to ownership provides the greatest prospect of a successful program. Further information on this topic can be found in the excerpts from the Biomethane Application included in Appendix D.

4.3.5 Holding Upgrading Facilities Within The Larger Utility

In the previous Sections, the FEU have outlined why they believe that owning and operating upgrading equipment is a regulated activity, and that there is a sound rationale for retaining flexibility in the ownership model employed for the upgrading plant. In circumstances where FortisBC is to own and operate upgrading equipment, the upgrading plant should be held by the existing utilities rather than in a separate regulated entity created for that purpose and owned within the FortisBC group of companies. Two reasons why this make sense are as follows.

First, Biomethane injection falls within the existing business structures of FEI and serves natural gas customers. The alternative of holding the upgrading equipment in a separate regulated entity would require the implementation of transfer pricing between the two entities, but the cost of those services (as well as any costs of setting-up and maintaining a new company) would have to be captured in the supply contract price charged back to the FEU. This type of circularity makes little sense. Moreover, the transfer pricing policy addresses the pricing of resources and services provided by FEI to non-regulated businesses and does not apply to transactions between regulated utilities.

Second, the Commission has expressly acknowledged the regulatory efficiency benefits of operating under a single-utility model in the context of a small propane utility within the FortisBC group of companies (discussed further in Section 6), and the same logic applies here.

4.3.6 Summary: FEU Should Maintain Flexibility to Own and Operate Upgrading Equipment

In summary, owning and operating biogas upgrading equipment is a regulated public utility service under the *UCA*. It is in the public interest that FEI owns and operates biogas upgrading equipment where commercial circumstances warrant; demonstrating flexibility in this regard will best ensure that Biomethane projects are brought forward and not unnecessarily hindered by financial and technical obstacles. Although the interconnection and monitoring facilities owned by FEI ensures that the Biomethane injected into the system is safe and of the necessary quality to protect the integrity of FEI's distribution system, the upgrading process determines how much safe and to-specification Biomethane reaches the point of interconnection. A reliable flow of quality Biomethane is required to meet customer demand for this product. This model helps protect customers by allowing FEI to best respond to customer concerns and demands and ensure the best quality gas possible. The risks associated with owning and operating upgrading equipment are modest and do not outweigh the benefits described above. In cases where FortisBC is to be involved in upgrading, the upgrading facilities should be held in the FEU, thus avoiding the need to establish and maintain other small utilities for that purpose.

4.4 COMPARISON TO OTHER JURISDICTIONS

Canadian natural gas utilities are slowly getting involved in the development of biogas business to generate electricity or to offer Biomethane Service in conjunction with natural gas for direct use. Unlike in other jurisdictions, in BC, the *UCA* supports the development of biogas business as a regulated utility.

4.4.1 Enbridge Gas[49]: Ontario

The City of Toronto is discussing with Enbridge Gas the development of a Biogas Pilot Project whereby Enbridge Gas will install, own, and operate a biomethane system at City of Toronto's waste management site. The biomethane will be injected into the Enbridge natural gas system. If the project is successful the biomethane will be used to generate electricity and / or direct use heating. It is estimated that output of biomethane from the project will reach 123,000GJ by 2013. Enbridge Gas plans to undertake more projects in the future and prefers a model that requires the biogas developers to own the upgrading plant while the company will be responsible for monitoring the quality of the biomethane.

---

[49] Authority to Enter into a Biogas Pilot Project Agreement with Enbridge Gas Distribution Inc. to Supply, Install, Own and Operate a Biomethane System at the Dufferin Waste Management Facility, http://www.toronto.ca/legdocs/mmis/2010/pw/bgrd/backgroundfile-29805.pdf

4.4.2 Gaz Metro[50]: Quebec

Gaz Métro is developing biomethane projects. Gaz Métro, Waste Management and Cascades are operating a biogas project that uses landfill gas to power Cascades' fine paper plant. Waste Management captures the biogas from the landfill and Gaz Métro compresses and transports it from the landfill site to Cascades paper plant.

4.4.3 Summary: Biomethane Services in Other Canadian Jurisdictions

Despite the limited experience in these developing areas to date, there are useful parallels to the FEU's proposed ownership model within British Columbia and elsewhere in the electricity context.

While in other jurisdictions the utility business model could be different from what FEI has proposed, it is important to note that our business model is supported by British Columbia's legislative framework, which contemplates regulation of upgrading and there are valid reasons for FEI's involvement in this aspect of biogas upgrading.

FEI's supply model for Biomethane upgrading is similar to the supply models in the electricity sector. Generally, electric utilities in Canada are vertically-integrated. This means that the electric utilities generate power as well as provide the transmission and distribution service to customers. It is also common for vertically-integrated electric utilities to have the flexibility to purchase power from other suppliers (i.e. IPPs) that can generate electricity at reasonable costs. BC Hydro represents a good example of this model; since the re-integration of BCTC in 2010, BC Hydro has been involved in all of generation, transmission and distribution activities. It also buys power from IPPs (through the standing offer program, for instance) and from the market. FEI's Biomethane business model has the same flexibility and allows:

- For the FEU's involvement in the production of Biomethane from the raw biogas (compared to BC Hydro's production of hydroelectricity from water); and
- The FEU to purchase Biomethane from suppliers who have the ability to supply a product which meets FEI's criteria and at reasonable costs (compared to an IPP producing hydroelectricity and selling it to BC Hydro).

As a result, there is broad precedent for the type of vertical integration that is contemplated, on a very small scale, with the Biomethane upgrading assets. This flexibility is important and will promote better pricing for customers who choose to elect into the program over time.

---

50 Waste Management, Gaz Metro and Cascades Partnership, http://www.solidwastemag.com/news/waste-management-gaz-m-tro-and-cascades-partnership/1000040688/

4.5 GUIDELINES FOR BIOMETHANE UPGRADING OWNERSHIP

As set out above, FEI believes that the appropriate time to address guidelines for most aspects of future Biomethane development is at the end of the two-year test period, as contemplated in the Biomethane Decision. FEI does believe that this Inquiry is an appropriate forum for addressing the ownership issue that was left unresolved in the Biomethane Decision. For the reasons stated above, FEI believes that the Commission should find that FEI's flexible approach to ownership and operation of upgrading facilities is appropriate and should be approved by the Commission.

The FEU submits that the following are appropriate guidelines regarding Biomethane upgrading:

1. It is important for the FEU to own and operate the *interconnection* facilities (i.e. measuring, monitoring, and odourizing) to ensure the quality and safety of the biomethane being injected into the distribution system.

2. Facilities for the *collection* of raw biogas (e.g. digester) are unregulated. Where the FEU are to become owners and operators of collective facilities, appropriate mechanisms would have to be put in place to reflect the non-regulated nature of the business. As the FEU are not currently anticipating owning and operating biogas collection facilities, no further guidelines on this matter are required at this time.

3. The FEU should consider proposals from project partners[51] to own and operate the upgrading facilities, and assess whether those partners can demonstrate financial and technical capability to do so.

    (a) he FEU's assessment of financial capability should involve consideration of whether the partner has financial resources to purchase and operate the equipment, and manage contingencies such as equipment failures or system improvements that may require additional capital.

    (b) The FEU's assessment of technical capability should involve consideration of whether the project partner has a strong technical knowledge of gas and gas related equipment.

    The FEU should also give consideration as to whether the project partner proposing to own and operate the upgrading facilities can provide the upgrading service for the same or lower cost than would be the case were the FEU to own or operate the upgrading facilities.

[51] This might be the owner of the collection facilities, or a third party. It is anticipated that if a third party were to become involved, it would likely be as a project partner with the owner of the collection equipment such that the true owner and operator would be the owner of the collection equipment, rather than purchasing raw biogas, upgrading it, and reselling it to FEU at a mark-up. However, the FEU would give consideration to proposals under either scenario.

2. The Commission recognizes the benefit of a streamlined regulatory process when it comes to Biomethane supply projects, and also recognizes that energy supply contracts are typically accepted by the Commission without process and supplemental evidence. Therefore, the following procedural guidelines are appropriate:

   (a) The CPCN threshold established for the FEU (currently $5 million) applies to biomethane upgrading facilities to be owned and operated by the FEU. Projects that are estimated to cost in excess of the threshold shall be reviewed through the ordinary CPCN process and in accordance with the Commission's CPCN guidelines.

   (b) The FEU is at liberty to apply for an expenditure schedule for upgrading facilities costs below the CPCN threshold, or otherwise have the costs considered in the normal course as part of a future revenue requirements process.

   (c) When filing contracts for upgraded biomethane (i.e. the project partner, and not the FEU, owns and operates the equipment for upgrading the biogas to biomethane), without the FEU seeking an expenditure schedule or a CPCN it will be sufficient for the FEU to file only the supply contract under section 71 of the *UCA* with information confirming that the supply is required. In such circumstances, the Commission expects that its consideration can normally occur without further process.

   (d) When filing supply contracts for raw biogas (i.e. where the FEU will own and operate the equipment for upgrading the biogas to Biomethane) under section 71 of the *UCA*, in addition to any other information confirming that the supply is required, the FEU will provide the following information to the Commission in summary form:

      (i) Confirmation that the owner of the collection facilities is not interested in owning upgrading facilities; or

      (ii) If the project partner remains interested in owning and operating the upgrading facilities, but the FEU is instead proposing to own and operate the upgrading facilities itself based on its assessment of the items identified in 3 above, the FEU's assessment of why (with reference to the items identified in 3 above) the FEU ownership is preferable.

5 NATURAL GAS VEHICLES SERVICE

The NGV Application filed on December 1, 2010, sought approval of the necessary General Terms and Conditions to permit FEI to provide a NGV Service offering consisting of Compressed Natural Gas and Liquefied Natural Gas Services. NGV Service involves the FEI owning and operating fueling assets, and charging the customer a rate that is based on the cost of service associated with those fueling assets. The Commission has recently issued the NGV Decision[52], setting revised terms and conditions for the provision of the CNG/LNG Services. The FEU are committed to expanding NGV load for the benefit of natural gas and NGV customers and in support of Provincal policy, and will offer CNG/LNG Service within the paramaters allowed by the NGV Decision. The FEU will re-file the GT&Cs incorporating these directives in due course.

In this Section, the FEU explain the role of CNG/LNG Service as a New Initiative, and propose guidelines for the efficient review of future applications related to CNG/LNG assets or services needed to develop the NGV marketplace.

This Section is organized as follows:

- Section 5.1 summarizes, for background, FEI's NGV business model that is reflected in the Commission-approved rate design;
- Section 5.2 explains the scope of the Commission's jurisdiction to regulate fueling assets and the service provided by them;
- Section 5.3 explains the role of NGV in the context of the New Initiatives;
- Section 5.4 summarizes the rate design requirements for the CNG/LNG Service that have been directed by the Commission; and
- Section 5.5 proposes additional guidelines to complement the directives in the NGV Decision.

5.1 FEI OFFERS A COMPLETE NGV SERVICE TO THE CUSTOMER

In this Section, the FEU provide a high level summary of the business model and rate design flowing from the NGV Application, for background purposes. In Appendix E, the FEU have provided excerpts from the 2008 and 2010 LTRPs, and the NGV Application, for further detail.

[52] Order No. G-128-11, dated July 19, 2011, included in Appendix H.

The FEU business model for CNG/LNG Service is to target fleet customers; primarily return-to-base commercial fleets and fleets that operate between a limited number of destinations, where refueling can occur at the end of each day at the same location. These fleets include buses and heavy-duty or vocational trucks that have Original Equipmnet Manufacturers ("OEM") availability in BC. Under the model, FEI installs, owns and maintains the necessary fueling facilities for a fleet and enters into long-term "take-or-pay" contracts. The individual agreements will be filed on a non-confidential basis with the Commission for approval pursuant to sections 59-61 of the *UCA* as a Tariff Supplement. The agreement between FEI and Waste Management of Canada Corporation ("WM") for CNG Service, which was approved by the Commission in the NGV Decision, followed this model.

The NGV Decision identified other rate design elements that must be reflected in future contracts. They included:

- Use actual construction costs as opposed to forecast costs;
- Fully recover the capital cost of the fueling station (including estimated negative salvage value) within the term of the contract or include provisions requiring the customer to purchase the equipment for its undepreciated capital cost;
- Ensure that actual operating and maintenance costs are recovered as fully as possible;
- Inflate operating and maintenance costs by the regional Consumer Price Index annually;
- Reflect no amount for capitalized overhead such that all operating and maintenance costs are recovered from the CNG/LNG customer over the term of the contract; and
- Provide an allowance for overhead and marketing to be recovered from the CNG/LNG customer.

As discussed below in Section 5.3, CNG/LNG Service provides customer benefits and supports British Columbia's energy objectives. The advantage of the business model inherent in the rate structures approved by the Commission is that the FEU invest in the fueling assets only where there is proven demand backed by a long-term take or pay contract.

5.2 CNG/LNG SERVICE PROVIDED BY THE FEU IS REGULATED PUBLIC UTILITY SERVICE

The FEU's provision of CNG/LNG Service is subject to regulation as a "public utility" service. The scope of regulated services is defined with reference to the definition of "public utility" in the *UCA*. CNG and LNG Service involves the "production, generation, storage, transmission, sale, delivery or provision of … natural gas…" to the public for compensation. The definition of "public utility" contains an exclusion for the "petroleum industry" (defined as including the retail distribution of CNG and LNG), but only to the extent that the "petroleum industry" entity providing the service is "not otherwise a public utility". Thus FEI, as a regulated public utility, can only offer a *regulated* CNG or LNG service[53]. An entity that is not otherwise a "public utility" can provide CNG or LNG service without being subject to regulation by the Commission. The Commission confirmed this in its decision as follows:

> *"Further, the Panel finds that a CNG/LNG fuelling infrastructure has no natural monopoly characteristics and the service offerings applied for would not be subject to regulation, unless the services were being provided by an organization that is already a regulated public utility."* [54]

The proposed LNG Service involves transportation of LNG by tanker from the LNG facility to the fueling station, but the same "public utility" analysis applies. There is no requirement under the *UCA* for the energy delivered to the public to be transported by pipe all the way from the source to the end user. By analogy, a diesel-fired electricity generator in a remote community is still providing public utility services to the community even though the diesel fuel used to produce the electricity is delivered by truck to the generator. The same is true for the Revelstoke propane utility which receives propane by truck and train, as was formerly the case for the FEW propane utility.

5.3 THE BENEFITS COMMON TO ALL CNG/LNG SERVICE PROJECTS UNDER APPROVED RATE DESIGN

In the 2008 and 2010 LTRPs and the NGV Application, the FEU articulated three key benefits associated with the FEU's investment in NGV fueling facilities under the "take-or-pay" rate design approved by the Commission:

1. Lower delivery rates for existing customers, all else being equal;
2. Economic benefits for fleet owners, which can also over time translate into savings for the customers of the NGV fleet; and
3. Advancement of British Columbia's energy objectives.

The FEU's evidence on each of the three benefits described above and in the NGV Application is summarized below. The key point for the purposes of this Inquiry is that these benefits are common to all CNG/LNG project investments backed by the approved "take-or-pay" rate design. Recognizing these commonalities in guidelines as proposed in Section 5.5 and Section 8 will

---

53 *UCA*, s. 1, "public utility Section 3 sets out the legal analysis in greater detail as to why the CNG/LNG Service is a public utility offering under the *UCA*.

54 Order No. G-128-11, dated July 19, 2011 (Reasons for Decision, Appendix A, page 4), included in Appendix H. As alluded to in Section 3, Legal Framework, the FEU takes issue with the relevance of the "monopoly characteristics" in determining the scope of regulation, given the nature of the definition of "public utility". This will be addressed in our final argument.

enable some procedural efficiencies in the Commission's consideration of future CNG/LNG Service projects.

5.3.1 Benefit to the Existing Customers through Lower Delivery Rates

The FEU discussed in Section 2.1 how the Companies have been experiencing declining use per customer and total throughput in recent years as a result of factors that include the greater penetration of high-efficiency appliances and the use of other energy forms. This leads to upward pressure being exerted on delivery rates. The FEI's investment in an NGV fueling facility brings immediate and lasting delivery-rate benefits to FEU's existing natural gas customers by facilitating the addition of natural gas load. The addition of cost-effective NGV load on FEI's distribution system favourably affects customer delivery rates in two ways:

- First, delivery costs are shared over more GJs of natural gas, thus reducing the delivery charge per GJ; and
- Second, adding NGV load is one of the few means available to FEI to combat declining throughput which continues to impact FEU's long term business risk and affects the utility's cost of capital.

Each of these benefits are further addressed below.

The "take-or-pay" contracts will ensure additional throughput on the FEI system for at least the life of each contract. For example, the WM and Vedder contracts are expected to add 21,000 GJs and 138,000 GJs respectively per year, for at least ten years, on the FEI distribution system. This is equivalent to adding 1,674 average Lower Mainland residential customers or 18 percent of the total 2010 customer additions. The forecast incremental delivery margin from an additional 21,000 GJs throughput on the FEI delivery system associated with the WM Agreement is approximately $40,000/year. FEI estimates that by 2030 the NGV business will add 30 PJs to the FEI system or 6.5 percent of the projected motor fuel market. This supports FEI's belief that over the long term, the heavy duty transportation sector in BC represents a large potential opportunity to increase natural gas throughput on FEI's system and offset some of the effect of declining use rates discussed in Section 2.1.

Second, the utility's cost of capital is directly linked to the FEU's long-term business risk, and the sustained decline in throughput is contributing to increased business risk. Government policy that is targeted at reducing GHG emissions and public perception of natural gas as less "green" than electricity for heating applications, among other factors, make it more difficult now than in the past to combat declining use rates by adding load from traditional end uses. Declining throughput and use rates places upward pressure on customers' delivery rates, and contributes to reduced competitiveness of natural gas versus greener sources of energy. NGV represents a significant opportunity for FEI to add cost-effective natural gas load and mitigate declining use per customer rates among core customers, while achieving GHG emissions reductions. As stated in Section 2.4.2, NGV is accepted by customers and stakeholders as a solution going forward that reduces GHG emissions.

These benefits can be achieved without imposing stress on the existing system assets. NGV load is high-load factor load, which improves the efficient use of the existing system. FEI has adequate system capacity to serve many incremental NGV customers, with impacts on system capacity being localized. Each NGV customer will be subject to the Main Extention ("MX") Test in the normal course to ensure that any required system upgrades to bring natural gas to the CNG/LNG fueling facility are economic for the system or are recovered from the NGV customer through a Contribution in Aid of Construction. The contractual model that underlies the proposed rate design ensures that system additions to serve NGV load remain tied with committed demand. The customers will also pay for distribution service under an existing Rate Schedule.

In the NGV Decision, regarding the General Terms and Conditions, the Commission held:

> *"The Panel is persuaded that benefits will accrue to FEI, FEI's NGV customers, its ratepayers and the people of British Columbia if the NGV market can be kick-started. FEI's NGV customers could potentially save a significant amount on their fuel costs <u>and its ratepayers may enjoy some rate stability or even a reduction in terms of delivery charges, other things being equal, if the load building that is forecast can be realized in the longer term</u>."* [Emphasis added] [55]

The guidelines proposed in Section 5.5 and Section 8 recognize that FEI's direct investment in NGV facilities will benefit the existing customers with little risk, since each NGV customer will bear the full cost associated with the provision of the NGV service based on the Commission's NGV Decision.

FEI notes that the Commission realizes the potential negative impact of the amended GT&Cs on the development of the NGV business:

> *"Accordingly, the Commission Panel has determined that to be approved, the General Terms and Conditions must include a provision requiring the customer to pay any unrecovered capital in those cases where the initial contract is not renewed, or a similar provision that provides equivalent protection. The Panel understands adding this provision may result in some potential customers being lost because they are not prepared to bear that risk."* [56]

With that being said, FEI will be amending the GT&Cs to reflect the Commission determination.

[55] Order No. G-128-11, dated July 19, 2011, page 30), included in Appendix H.
[56] Order No. G-128-11, dated July 19, 2011, page 22), included in Appendix H.

5.3.2 FEI's Investment Facilitates Delivery of Valuable Service to NGV Customers

In the NGV Decision, the Commission found that NGV projects can potentially bring significant benefits to NGV customers:

> *"The Panel is persuaded that benefits will accrue to FEI, FEI's NGV customers, its ratepayers and the people of British Columbia if the NGV market can be kick-started. FEI's NGV customers could potentially save a significant amount on their fuel costs."* [Emphasis added] [57]

These benefits will be common to all CNG/LNG Service projects under the current rate design. Fleet owners can save on operating costs over time by adopting NGVs and taking CNG/LNG Service facilitated by FEI's contractually-backed investment in fueling facilities. The savings flow from the difference in price between natural gas and diesel. Natural gas has held a price advantage over diesel during the past 10 years, with the gap widening since 2005. Market indications, as reflected in the forward market prices, show that natural gas is likely to retain its price advantage over incumbent fuels for the foreseeable future. Once any vehicle conversion costs have been recovered, the natural gas vs. diesel pricing differential represents cost savings for the fleet owner. The typical payback of conversion costs for a return-to-base heavy-duty fleet operator (FEI's target market) switching from diesel to CNG is approximately four to six years.

It is expected that over time the savings realized by the NGV fleet operator can translate into reduced costs for their customers using their services. An example of a way in which this might occur is though a municipality holding a competitive process for garbage collection, where one or more bidders is operating an NGV fleet with lower operating costs. The competition should result in a portion of the savings being passed on to the municipality over time, and the potential for this to occur increases the number of bidders that have adopted the lower-cost NGV technology. Further, this reduced cost to the municipality helps it provide more cost-effective service to their residents. In this way, the benefits that accrue to NGV fleet owners can translate into broader public benefits. This benefit can also happen directly if government organizations that use buses or ferries make use of NGV fleets.

The second way in which fleet owners benefit from FEI investing in facilities required to make natural gas available in a usable form is that natural gas as a vehicle fuel will tend to be subject to less price volatility than diesel or gasoline. This relates primarily to the fact that the delivery rate component of natural gas service represents a significant component of the total fuel cost paid by NGV customers, and it is set annually. NGV customers also have the option of purchasing the commodity under rates where the commodity price is set on a quarterly basis. Diesel and gasoline, by contrast, are priced according to constant fluctuation more akin to a spot market, and the cost of delivery (tanker) represents a smaller component of the delivered

[57] Order No. G-128-11, dated July 19, 2011, page 30), included in Appendix H.

cost of diesel or gasoline. The value of the reduced volatility to fleet owners will depend on the fleet owner's specific circumstances and the price elasticity of the markets in which they compete (e.g. can the fleet owner pass on the cost variances to its own customers).

The third way in which FEI's investment can benefit fleet owners is by enabling fleet owners to access a lower carbon fuel relative to diesel or gasoline, and thus reduce their GHG emissions. There are businesses that wish to employ measures to reduce their carbon footprint as a matter of principle. The reduced carbon output associated with CNG and LNG relative to diesel may also create competitive advantages for the fleet owner that complement the fuel cost savings. An increasing number of municipalities have introduced procurement policies which favour clean air standards for garbage trucks, and as a result fleet operators running NGVs may hold an advantage in winning competitive bid contracts due to the GHG savings associated with NGVs. Public service organizations or municipalities that have made commitments to be carbon neutral will also see benefits from NGVs. As mentioned in Section 2.2.5, the City of Surrey is an example of an organization that is aiming to achieve GHG emissions reduction benefits using compressed natural gas vehicles. The city is seeking a proponent to provide waste management services and one of its objectives is, "*the reduction of adverse environmental impacts from the performance of the Services, including where appropriate the adoption of clean technologies*" [58].

The guidelines proposed in Section 5.5 and Section 8 recognize that, while the magnitude of benefits for fleet owner may vary from project to project, all CNG/LNG Service projects undertaken under the current rate design will provide such benefits.

5.3.3 CNG/LNG Investment Advances "British Colubmia's Energy Objectives"

The Commission's NGV Decision recognized that CNG/LNG Service advances "British Columbia's energy objectives" and provincial policy generally. Despite expressing some reservations about the scale of the benefits, the Commission specifically found that:

> *"The panel does accept, however, that the use of natural gas as a fuel will result in fewer carbon and other emissions than the diesel which it replaces and the Application is therefore consistent with the energy objectives which relate to the reduction of greenhouse gas emissions… The Panel further accepts that there may be some economic development benefits in that certain component manufacturers for NGVS are located in British Columbia."* [59]

The nature of these benefits will be common to all CNG/LNG Service projects.

---

[58] City of Surrey, Request for Proposals, Waste management Collection Services.
[59] Order No. G-128-11, dated July 19, 2011, page 32), included in Appendix H.

As described in Section 2.2 and in the NGV Application, the 2007 BC Energy Plan forms the cornerstone of Provincial energy policy, and it provides support for fuel switching away from diesel to lower carbon fuels. For instance, the BC Energy Plan states:

> *"The government is committed to reducing greenhouse gas emissions from the transportation sector and has committed to adopting California's tailpipe emission standards from greenhouse gas emissions and champion the national adoption of these standards."*

The BC Energy Plan identified natural gas as a cleaner option in the transportation sector: "*Natural gas burns cleaner than either gasoline or propane, resulting in less air pollution*". Government policy thus generally places a new focus on NGVs, laying the groundwork for increased utilization of this technology in British Columbia.

As described in Section 2.2 of this Filing, the Provincial Government has given effect to policies set out in the 2007 BC Energy Plan in legislation such as the *CEA* and the accompanying amendments to the *UCA*. "British Columbia's energy objectives" apply to CPCN applications under section 45 of the *UCA* and applications brought under section 44.2 (among other sections), both of which relate to utility investments. The *Clean Energy Act* objectives that are relevant to the NGV offering include:

> *"g) to reduce greenhouse gas emissions… ;*
>
> *h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;"*

The objectives "to reduce greenhouse gas emissions …" and "*to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia*" are supported by fleet conversion from diesel to natural gas. The WM conversion, which required FEI's investment in NGV fueling facilities, will reduce GHG emissions by approximately 214 tonnes annually. The GHG savings associated with the WM Agreement are the equivalent of taking 41 cars off the road, or removing the emissions impact of 221 typical residential customers. A fleet expansion will be accompanied by additional GHG emissions reductions. As set out above, the NGV Decision acknowledged that FEI's initiatives are in alignment with "British Columbia's energy objectives"[60]. The Province also endorsed FEI's plan to pursue NGV initiatives in the FEI 2010- 2011 RRA, stating: "*The Ministry supports the expanded use of natural gas for vehicles (NGV) and biogas, and is encouraged that FEI intends to apply to the Commission for appropriate rates*".

This link between public utility investments and "British Columbia's energy objectives" is explicit recognition that Government intends public utilities to be investing in cost-effective initiatives

[60] Order No. G-128-11, dated July 19, 2011, page 16 and 32), included in Appendix H.

and facilities that advance the legislated objectives. The guidelines proposed in Section 5.5 and Section 8 recognize that, while the magnitude of benefits may vary from project to project, all CNG/LNG Service projects will support "British Columbia's energy objectives".

5.3.4 Other Public Interest Considerations: FEI's Role in the NGV Market

This Section addresses the FEU's role in the NGV market. The FEU anticipate that, in most cases, some entity with expertise in the CNG/LNG business will have to be involved in order to permit a fleet owner to adopt NGV technology. The FEU's CNG/LNG Service offers a means for fleet owners to obtain the benefits of CNG/LNG Service without having to manage the complexities of owning and operating assets for the delivery of high pressure gas or cryogenic fuel. Other options for third-party ownership of the fueling assets are currently limited in BC, and thus the FEU's CNG/LNG Service is vital for attaching NGV load and bringing the associated benefits. In the event that future third-party providers of CNG/LNG Service enter the BC market in a significant way, there is still a role for the FEU in providing CNG/LNG Service. The guidelines proposed in Section 5.5 and Section 8 reflect the importance of the FEU's continued involvement in providing a regulated CNG/LNG Service.

5.3.4.1 Complexities of Owning and Operating Fueling Assets

Owning and operating assets for the delivery of high pressure gas or cryogenic fuel is complex. The FEU anticipate that, in most cases, some entity with expertise in the CNG/LNG business will have to be involved in order to permit a fleet owner to adopt NGV technology. Also, even where fleet owners are sophisticated, they may not want to own the fueling assets because these are not part of their core business. This was the case with Waste Management.

5.3.4.2 FEU is Currently Active in Providing CNG/LNG Service for Customers

Although other non-regulated options have been available in the BC market for quite some time (exercised by such firms as Clean Energy and BC Transit), the market has failed to develop in such a way that would ensure our existing customers benefit from the increased throughput. The number of stations in BC has declined from 52 in 2002 to approximately 16 today. WM, currently taking service under the WM Agreement, is the first new heavy duty commercial NGV fleet in BC in the recent years. Further, the Commission recently approved the interim service contracts for Vedder Transportation, which will use LNG for their initial fleet of 50 trucks. The market had stagnated prior to FEI's involvement in promoting CNG/LNG Service as a regulated service. It is reasonable to conclude that, if FEI does not provide the service, the potential to build NGV load on FEI's system and deliver the attendant benefits will be delayed or may not occur.

5.3.4.3 FEU Should Continue to Be Involved Once the Market is "Kick Started"

FEI's initiative leaves other operators involved in the business of providing CNG and LNG Services free to pursue projects, and the public interest is not served by excluding the FEU from the NGV market now or at any point in its evolution.

The FEU are capable of providing cost-effective NGV service, and this enhances the economic benefits for fleet owners interested in NGV service, thereby making it more likely that FEU will be able to add cost-effective natural gas load and promote GHG emissions reductions. These savings can translate into saving for end use customers over time. Assuming that other providers emerge over time, they should have to compete with the FEU. The rate design that the Commission has approved requires that the Companies will recover the full cost associated with NGVs from the NGV customers and will eliminate the potential for cross subsidization by existing ratepayers[61]. FEI believes that, from the perspective of FEI's customers and owners of fleets considering NGV, it is not in the public interest to insulate other potential providers of CNG/LNG Services from competition from a respected provider of natural gas services like FEI. Insulating third-party providers from competition from the FEU's cost of service based rates has the effect of transferring the benefits of cost savings that should accrue to customers to unregulated third-party providers as windfall profit gains.

It is correct that the FEU could still hold assets in a non-regulated entity, and if permitted by the Commission, share services through a transfer pricing mechanism. However, FEI submits that it is equitable for the regulated utility to make investments intended to combat declining throughput and ensure the long-term viability of the utility for the benefit of both customers and the shareholder. The customers' interest in adding cost-effective load is in reduced delivery rates (all else equal), while the shareholder is seeking to ensure that its investment in the total distribution system assets can be recovered in the long term. These interests are aligned. In this respect, the proposed investment is no different from other utility investments associated with adding customers and throughput. For this reason, FortisBC Holdings Ltd. is interested in owning and operating NGV fueling stations only through its regulated utility subsidiaries, so that the risks associated with the investment, albeit modest, are properly borne by all beneficiaries of the investment under the regulatory compact.

---

[61] The Commission directed in the NGV Decision (p. 30) that the amended GT&Cs, in addition to having a take-or-pay commitment, must reflect that the rates charged to customers: (1) Use actual construction costs as opposed to forecast costs; (2) Fully recover the capital cost of the fueling station (including estimated negative salvage value) within the term of the contract or include provisions requiring the customer to purchase the equipment for its undepreciated capital cost; (3) Ensure that actual operating and maintenance costs are recovered as fully as possible; (4) Inflate operating and maintenance costs by the regional CPI annually; (5) Reflect no amount for capitalized overhead such that all operating and maintenance costs are recovered from the CNG/LNG customer over the term of the contract; and (6) Provide an allowance for overhead and marketing to be recovered from the CNG/LNG customer.

5.3.4.4 Summary: NGV Service Supports Public Interest Considerations

Existing customers and potential NGV customers benefit from the immediate and sustained involvement of FEI, which has proven expertise and knowledge, a reputation as a safe and reliable integrated energy provider, and a singular BC focus. Recognizing the benefits of NGV Service, a number of stakeholders and customer groups supported FEI's approach to the EEC incentives for fleets as well as FEI's ownership and operations of fueling assets. These letters of support are included in Appendix B. The proposed guidelines in Section 5.5 and Section 8 support this logic and recognize the continued importance of FEU's role going forward.

5.3.5 Allocation of Risk May Slow Market Uptake

In the NGV Decision, the Commission adjusted the CNG/LNG Service rate design to shift more risks to the potential NGV customer. The FEU believe that this change has the potential to discourage customers from choosing NGV ahead of diesel. The basis for that view is set out below.

In the NGV Application, the FEU emphasized that there are commercial realities that potential fleet owners take into consideration in deciding whether to switch from diesel to natural gas. The potential NGV customers are faced with having to compare the uncertain NGV Services with the relative ease of access and use associated with gasoline and diesel fuel. Current users of diesel and gasoline technologies enjoy a complete end-to-end service offering, whereby the fueling infrastructure, delivery of the fuel, and operation and maintenance of a station is all taken care of, and the customers are only responsible for the purchase of their fuel at the pump. Fleets considering conversion to natural gas know that they can contract with fixed price certainty for the installation of diesel fueling facilities and expect NGV fueling infrastructure suppliers to offer price certainty to be competitive with the incumbent offering. In the absence of a competitive offering with respect to this element of the fueling service package, customers may not switch to NGVs.

In addition, FEI believes that if it were to attempt to sell fueling station services based on costs that are estimated and where the project risk of project overruns is solely borne by the NGV customer, NGV customers will perceive a lack of confidence with respect to the NGV stations and will be less likely to proceed with NGV service. This perception would slow down the adoption of NGVs.

The Commission recognized the potential negative impact of the amended GT&Cs on the development of the NGV business, and expressed a willingness to accept some loss of potential customers:

> *"Accordingly, the Commission Panel has determined that to be approved, the General Terms and Conditions must include a provision requiring the customer to pay any unrecovered capital in those cases where the initial contract is not renewed, or a similar*

> *provision that provides equivalent protection. The Panel understands adding this provision may result in some potential customers being lost because they are not prepared to bear that risk."* [62]

The FEU's evidence in the 2012 and 2013 RRA is that from a revenue generation and station capital perspective, FEI believes that the additional terms and conditions imposed on FEI with respect to developing fueling station agreements will make it significantly more challenging to conclude agreements with customers. Although the NGV Decision may pose additional challenges, FEI believes that it can overcome these challenges and that the growth in the market can be achieved. However, should that prove to be incorrect, the benefits to existing natural gas customers of the additional requirements imposed by the Commission may be counterproductive. The proposed guidelines in Section 5.5 and Section 8 invite the FEU to seek changes in the approved rate design should new evidence come to light on the extent to which potential customers are being lost.

5.4 COMPARISON TO OTHER JURISDICTIONS

A number of Canadian natural gas distribution utilities have taken the steps in providing natural gas vehicle services to customers and their initiatives are described below. The information provided shows a varied approach to the provision of NGV and different regulatory constructs.

5.4.1 Gaz Metro: Quebec

Gaz Metro's involvement in the NGV business is through Gaz Metro Transport Solutions an unregulated company that is wholly owned by Gaz Metro Plus, a subsidiary of Gaz Metro. The company is focussed on heavy haul transportation customers and offers NGV services that include[63]:

- evaluating the feasibility of NGV projects;
- helping obtain grants offered by the various levels of government;
- designing compression and/or storage installations;
- building, operating, maintaining and financing such installations to meet specific needs each customer;
- supporting the promotion of projects;
- supplying liquefied or compressed natural gas; and

---

62 Order No. G-128-11, dated July 19, 2011, page 22), included in Appendix H.
63 GazMetro Transport Solutions, http://www.corporatif.gazmetro.com/Data/Media/GMST_ang.pdf.

- metering.

Pilot projects are underway for both LNG and CNG Services. In the case of LNG, three LNG refueling sites are planned for the corridor formed by Highway 20 greater Québec area and Highway 401 greater Toronto area. A pilot compressed natural gas project is being developed for garbage collection trucks.

5.4.2 Enbridge Gas[64]: Ontario

Enbridge Gas' target market is light-duty commercial vehicles, medium-duty trucks and the refuse trucking market. The company also generates substantial gas sales to the off-road fork lift market. Enbridge Gas owns and operates the refueling assets which they rent to customers. The NGV business is regulated and the company earns a regulated return on the assets.

5.4.3 SaskEnergy[65]: Saskatchewan

SaskEnergy's NGV offering serves all market segments but the company's priority is its own fleet. SaskEnergy owns and operates 8 refueling stations that serve its fleet while any other refueling facilities are owned and operated by other participants. SaskEnergy provides service to some local fleets and occasional drive-up customers but does not actively market NGV offering to the general public. SaskEnergy's NGV activity is primarily for energy conservation and efficiency purposes. The rates applicable to the NGV service are subject to approval by government, together with other natural gas rates.

5.4.4 ATCO Gas[66]: Alberta

ATCO's NGV business targets primarily commercial fleets and medium-duty vehicles, but also encourages the conversion of light-duty vehicles to natural gas. The company installs, owns and operates all its refueling facilities which are 11 in total. Those refueling assets that are deemed necessary to service the company vehicles are regulated and the remaining ones are not regulated.

5.4.5 Encana[67]

Encana is working with various levels of government in Canada to develop two natural gas corridors - one in western Canada (linking Vancouver, Calgary and Edmonton), and the other eastern Canada (linking Windsor, Toronto, Ottawa, Montreal and Quebec). The company's aim is to fuel 145,000 trucks by LNG, 2.5 million light-duty vehicles by CNG, owning more than 50

64 FEI had discussions with a representative of Enbridge Gas
65 FEI had discussions with a representative of SaskEnergy.
66 FEI had discussions with a representative of ATCO Gas.
67 Oilweek Magazine, http://www.oilweek.com/articles.asp?ID=732.

LNG plants across the country and a network of more than 900 CNG and LNG fueling stations countrywide.

5.4.6 Summary: Natural Gas Vehicle Services In Other Canadian Jurisdictions

As discussed in Section 2.3, energy policies and how GHG emissions are produced in each jurisdiction outside of BC are different than the energy environment in BC. In most jurisdictions outside BC, the use of natural gas for generating electricity and the use of natural gas in direct use application is supported. Given that these traditional uses of natural gas are supported, the NGV initiative may be of less importance to other utilities across Canada as compared to what the opportunity means to the FEU and their customers. In BC, the government's energy objectives and policies are focused on the reduction of GHG emissions and the use of natural gas in meeting these objectives in its traditional applications has been called into question[68]. These policies and how stakeholder and customer interpret these policies, can call into question the role of natural gas in meeting BC energy demand now and into the future. The NGV initiative as a whole is a significant opportunity for us to maintain throughput for the benefit of our customers.

5.5 PROPOSED GUIDELINES FOR NGV

As described above, FEI's investment in the NGV fueling stations provides delivery rate benefits for all non-bypass natural gas customers, provides fleet operators with access to a beneficial fuel alternative, which will translate to the end user benefits over time, and delivers GHG emissions reductions that advance government policy and benefits British Columbians generally. The nature of the benefits described above will remain consistent for all future investments in CNG and LNG infrastructure, with only the magnitude of the benefits differing in each case. Each cost-effective fueling project stands on its own in terms of being in the public interest, making it unnecessary at this time to determine how large the NGV market might become in the long term. As the benefits are clear on the evidence, the focus of this inquiry should be on ensuring support for the current FEI initiatives.

FEI notes that the Commission's NGV-EEC Decision[69] determined that the FEU did not have approval to use EEC monies to provide incentives for NGVs, which the FEU believe is key in the early days of "kick-starting" demand for CNG/LNG Service. The Commission is also of the view that the potential benefits to existing customers in the FEU's the long-term forecast of NGV load additions have not been established. These issues will have to be addressed in due course (there is a further process dealing with incentives for NGV as outlined in the NGV-EEC

[68] The BC Energy Plan A Vision for Clean Energy Leadership, Electricity Policies page 5 states, for instance: "The BC government has stated that it "*commits that all new natural gas or oil fired electricity generation projects developed in BC and connected to the integrated grid will have zero net GHG Emissions.*" In addition, existing electricity generating facilities will have to emit zero GHG emissions by 2016.

[69] Order No. G-145-11, dated August 15, 2011, included in Appendix H.

Decision), but cannot be resolved in this Inquiry. The proposed guidelines for NGV infrastructure can be put in place independently of those matters.

The proposed guidelines below will facilitate the efficient implementation of the CNG/LNG Service as approved in the NGV Decision:

2. The CPCN threshold established for the FEU (currently $5 million) applies to NGV facilities, including pumping facilities for individual customers, any needed system additions or upgrades that are necessary as a result of additional NGV load, or liquified natural gas supply resources or facilities involved with loading and transporting these products. Projects that are estimated to cost in excess of the threshold shall be reviewed through the ordinary CPCN process and in accordance with the Commission's CPCN guidelines.

3. The FEU are at liberty to apply for an expenditure schedule for the types of facilities outlined above when costs fall below the CPCN threshold, or otherwise choose to have the costs considered in the normal course as part of a future revenue requirement process.

4. The Commission has recognized in the NGV Decision that investments in fueling infrastructure necessary to facilitate CNG/LNG Service share common benefits, which include:

   (a) lower delivery rates for existing customers through added load, all else equal;

   (b) economic benefits for fleet owners;

   (c) advancement of British Columbia's energy objectives; and

   (d) a fair return on invested capital for the shareholder.

   Only the extent of these benefits will vary from project to project. Therefore, in the event that the FEU apply for acceptance of an expenditure schedule in respect of fueling station infrastructure, the evidence required by the Commission will generally be limited to the CNG/LNG Service agreement and a brief statement quantifying the following: the delivery rate impact, GHG emissions savings and general economic benefits captured by British Columbia's energy objectives; an estimation of fuel cost savings flowing to the fleet owner and any potential for those cost savings to be passed on to others (e.g. municipality contracting with the fleet owner for hauling service); and the shareholder's return on invested capital.

5. Regardless of whether the FEU apply for acceptance of an expenditure schedule for an investment in CNG/LNG fueling facilities, the Commission's approval of the associated CNG/LNG Service agreement will generally be persuasive evidence at the time cost recovery is sought that the FEU's decision to invest in the supporting assets (as opposed to how effectively the project was executed) was prudent. This is because the

rate design specified in the NGV Decision secures cost recovery from the NGV customers.

6. In circumstances where the potential NGV customer has selected FEI as its project partner for providing CNG/LNG Service, evidence of the existence of another third party alternative provider of a similar CNG/LNG service would only be given weight in the public interest assessment of the FEU's CNG/LNG fueling station project if the third party provider files evidence to establish that:

   (a) The customer (notwithstanding its contract with the FEU) wants to partner with the third party, and not FEU; or

   (b) The interest of the CNG/LNG Service customer in accessing service from the FEU as its preferred partner at a rate based on the FEU's cost of service:

      (i) is outweighed by the corporate interests of a non-regulated provider in providing that service despite the preference of the CNG/LNG Service customer to work with the FEU; and/or

      (ii) is outweighed by a long-term benefit to customers generally that flows from overriding the specific customer's preference to work with the FEU.

7. The Commission recognized in the NGV Decision that its directed modifications to the proposed CNG/LNG Service rate design could affect the rate of take-up of the service, and was satisfied with that trade-off to reduce risk to other natural gas customers. Nevertheless, the FEU are encouraged to apply for modifications to the approved CNG/LNG Service rate design based on new evidence that the approved rate design is presenting a significant impediment to the adoption of CNG/LNG Service, such that the interests of ratepayers in reduced risk is outweighed by lost opportunities to build load.

8. The Commission's NGV Decision addressed rate design in the context of CNG/LNG Service, which is focussed on recovery of costs associated with the fueling station. The FEU's investment in new or expanded upstream facilities, such as LNG production and storage, may give rise to different rate design considerations that would have to be addressed by the FEU.

6 THERMAL ENERGY SERVICES

British Columbians' heating and cooling requirements have traditionally been met by natural gas, electricity, other fossil fuels such as propane and heating oil, and a piped steam utility in Vancouver. There is now demand for thermal energy to be provided in alternative ways, such as through geo-exchange, waste heat recovery, biomass, solar thermal, and district energy systems. In this Section, the FEU discuss the initiative to provide Thermal Energy Services ("TES") as a regulated class of service within the utility and how it benefits customers, the public generally, and the shareholder. The FEU's participation in TES is responsive to customer demand, provides benefits to existing and future natural gas and thermal energy customers, and advances government's policy objectives. The FEU have proposed guidelines in Section 6.6 and Section 8 that, if adopted, will provide greater clarity about how the FEU's involvement in Thermal Energy Services can be done in a manner consistent with the public interest and maintaining just and reasonable rates for the natural gas and TES classes of service.

This Section is organized as follows:

- Section 6.1 provides an overview of what thermal energy systems are;
- Section 6.2 discusses the types of customers who will use these systems in British Columbia;
- Section 6.3 describes the FEU's role in the TES market, and in particular, the nature of the TES services that the FEU are offering to the public;
- Section 6.4 answers the regulatory issues that have been raised regarding the FEU's delivery of Thermal Energy Services. In particular, it describes why TES are regulated under the *Act*; the regulatory history of TES; how the *Act* accommodates multiple classes of service within a regulated public utility; rate design for TES; the regulatory treatment of TES in other jurisdictions; and related regulatory issues;
- Section 6.5 explains the benefits to customers and the broader public of the FEU providing TES; and
- Section 6.6 sets out the FEU's proposed guidelines for the review of TES projects.

6.1 OVERVIEW OF THERMAL ENERGY SYSTEMS AND CUSTOMER DEMAND

Thermal Energy Systems can be categorized in two different ways: by the type of or group of customer served, and by the technology employed to create the thermal energy. This Section begins with a discussion of the two general categories of TES ("discrete" and "district"). It then discusses specific types of systems and the technology employed (geo-exchange, waste heat recovery, solar thermal, and biofuels), and finally, it discusses the role of natural gas as a back-up fuel.

6.1.1 Discrete Thermal Energy System

The characteristics of a typical discrete TES contemplated by the FEU are as follows:

- A discrete system typically serves one customer (building type) in one or more buildings such as an individual home, a strata building, or a commercial property on one piece of land.
- Discrete energy systems employ a range of energy technologies and sources to deliver piped heating (ambient, hot water and/or steam) and/or cooling (ambient or chilled water) to one or more buildings and customers within a property from a central or distributed plant location or locations.
- There is usually only one class of customer and one charge or rate to the customer for energy. The target customers of this offering would be charged rates that would recover the FEU's cost of service, although the high upfront capital costs of these systems may necessitate the use of rate management techniques such as levelized rates to avoid prohibitively high rates for the initial customers joining the system. In these cases the rates would recover the cost of service over a longer time period such as the life of the assets or the term of the service contract. The rate includes cost recovery for capital, O&M (including energy inputs), taxes, depreciation, etc.
- The agreement to provide service is with the strata or commercial business, although the development of the discrete system is often carried out by a developer.
- Development of a discrete system is much quicker than the District Energy Systems described below due to the limited number of partners, stakeholders and customers.

6.1.2 District Energy Systems

The characteristics of a typical District Energy Systems ("DES") contemplated by the FEU are as follows:

- DES can serve a range of building use types (multi-family residential, commercial, institutional and industrial customers). Since DES are generally designed to serve multi-use neighbourhoods or communities, there are several levels of customer markets to consider.
- DES may use a single conventional energy source and technology such as high efficiency natural gas boilers to deliver large volumes of piped ambient, or hot water or steam throughout a neighbourhood or community typically from a central plant or

location. More recent developments employ a range of technologies and sources to capture latent waste heat from the environment, or geo-exchange supplemented by conventional energy sources and equipment to deliver piped heating (ambient, hot water and/or steam) and/or cooling (ambient or chilled water) to multiple buildings and customers.

- More recently, boilers are being designed to use biofuels such as wood waste to reduce reliance on fossil fuel use.
- There can be many classes of customer and corresponding rates to customers in respect of DES.
- The target customers of this offering would be charged rates that would recover the FEU's cost of service, although the high upfront capital costs of these systems may necessitate the use of rate management techniques such as levelized rates to avoid prohibitively high rates for the initial customers joining the system. In these cases the rates would recover the cost of service over a longer time period such as the life of the assets or the term of the service contract. The rate includes cost recovery for capital, O&M (including energy inputs), taxes, depreciation etc. Anchor customers may have separate negotiated rates with residential and commercial customers having postage stamp type rates.
- Municipalities seeking to improve energy efficiency and reduce carbon emissions in their communities are among the proponents of DES development.
- To develop a DES, agreements will typically need to be in place with municipalities, large anchor customers, heat providers/sellers (a hospital or industrial customer, for instance), and end use customers.
- Development of DES tends to take much longer than a Discrete Thermal Energy System due to the scope and scale of the projects being larger than discrete projects, but also due to the increased number of stakeholders involved, such as municipalities and other levels of government.

Figures 6-1 and 6-2 below depicts a typical DES, using a variety of energy inputs.

Figure 6-1: Example of DES

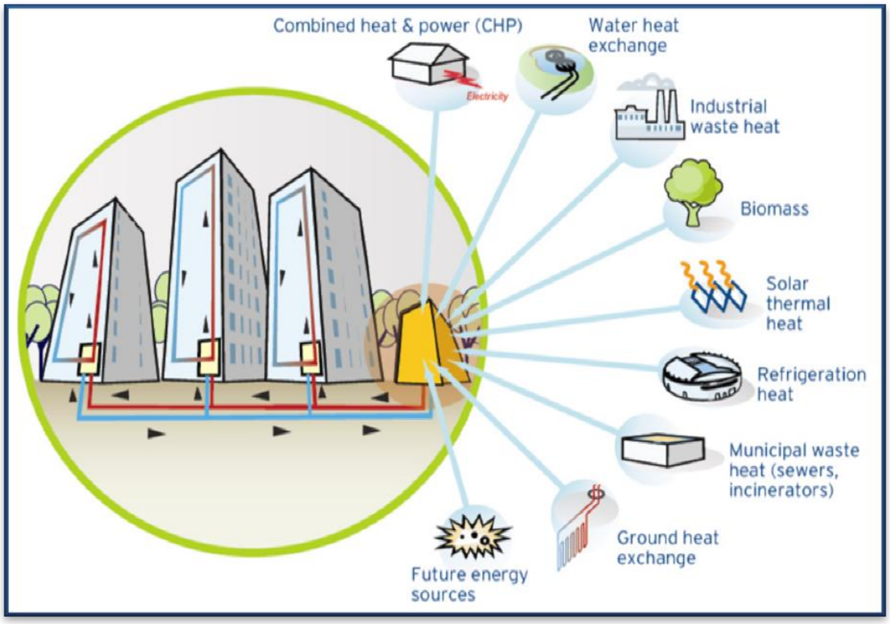
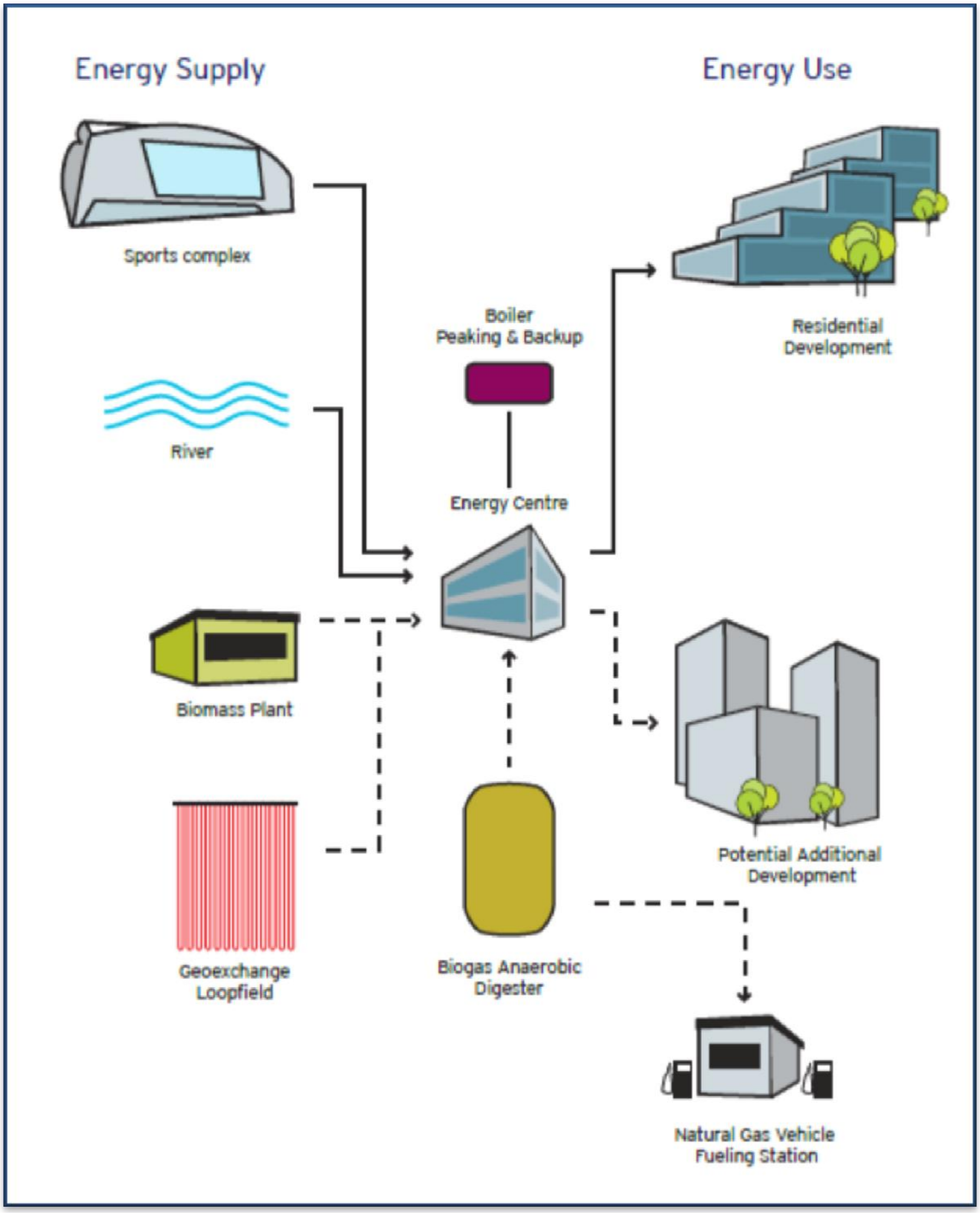


Figure 6-2 below depicts a typical DES showing the potential to use natural gas as a back-up fuel source and also how Biomethane and NGV fueling might be incorporated.

Figure 6-2: Example of DES Incorporating Natural Gas, Biomethane and NGV Fueling



Higher efficiencies and the potential to replace or combine conventional energy systems with renewable energy sources to improve system efficiency and reduce GHG emissions are among the reasons for implementing discrete thermal systems and DES. For some larger customers, energy savings can also be a driver to move to a DES.

The combination of fuel sources and technologies employed by each discrete and DES will be unique, but most projects will have common elements. Heat capture systems include a separate piping system that captures the heat energy from its source, similar to those described for geo-exchange systems (discussed below). One or more central plants are located in specially designed mechanical rooms or buildings, housing boilers, heat exchangers, pumps and piping infrastructure. Piping systems will then distribute ambient/hot water and/or steam to buildings and customers within the service area. Finally, each building or unit served by the DES may contain specific equipment to convert the distributed steam, hot water or ambient temperature fluid into useable energy specific to the needs of that customer.

Multiple renewable systems can also be employed in combination with the conventional energy. For example, geo-exchange systems can provide space heating and cooling while a solar-thermal installation can provide a portion of the domestic hot water needs to the same multi-family or multi-use building. DES (and in some cases large discrete systems) can employ multiple energy sources and systems to balance the heating and cooling needs for a community with many end use needs.

The FEU view DES and discrete energy as important parts of its future TES offering.

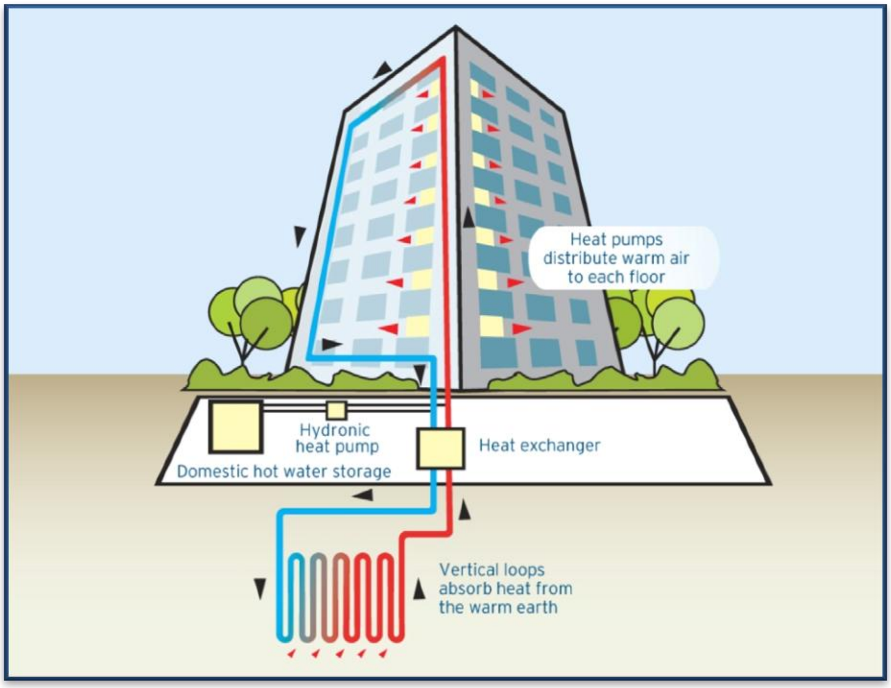
6.1.3 <u>Thermal Energy Technologies</u>

Both Discrete Thermal Energy Systems and DES use a range of technologies to provide thermal energy. Some of these systems are more common to either discrete or DES, but most can be used with either type of system. The following is a description of some typical thermal energy technologies including geo-exchange systems, heat capture and exchange, solar-thermal systems, and biofuel systems. In all Thermal Energy Services, the FEU's intention is to maintain natural gas as a component of the overall energy solution as an alternative to electricity.

6.1.3.1 Geo-exchange

Geo-exchange systems - also referred to as geo-thermal systems, earth exchange systems or ground and water source heat pumps - utilize the heat energy contained in near surface layers of the earth, ground water and surface water. A subsurface piping system contains a liquid that absorbs heat from the surrounding material and delivers it to a central heat exchanger. High efficiency heat pumps convert this energy into hot water or steam contained in a separate piping system that then delivers the heat energy to where it is required for space heating and hot water uses. Centralized equipment is usually contained within a specially designed mechanical room that serves the entire development. The heat exchanger is reversed to provide space cooling, removing heat from the building(s) and returning it to the subsurface substrate. Figure 6-3 below demonstrates how geo-exchange systems work.

Figure 6-3: Geo-Exchange Systems



The demand for Geo-exchange services typically comes from owners and/or operators of larger single or multi-use buildings including municipal, institutional, multi-family residential and commercial end users. Such a system or systems primarily serve one or a few buildings, but can also be designed to provide energy for district energy systems when built on a larger scale. Both installation and ongoing O&M for geo-exchange systems can be provided either directly by the FEU or through partners such as energy service providers.

6.1.3.2 Heat Capture and Exchange

In addition to geo-exchange systems, heat can be captured, transported and consumed using additional heat sources such as sewage waste heat capture, industrial heat capture, and institutional capture (from sources such as pools or skating rinks). For example, the latent heat from wastewater effluent flows feeding a nearby sewage treatment plant can be captured and converted to useable energy in much the same way that geo-exchange systems capture and convert latent heat from below the surface.

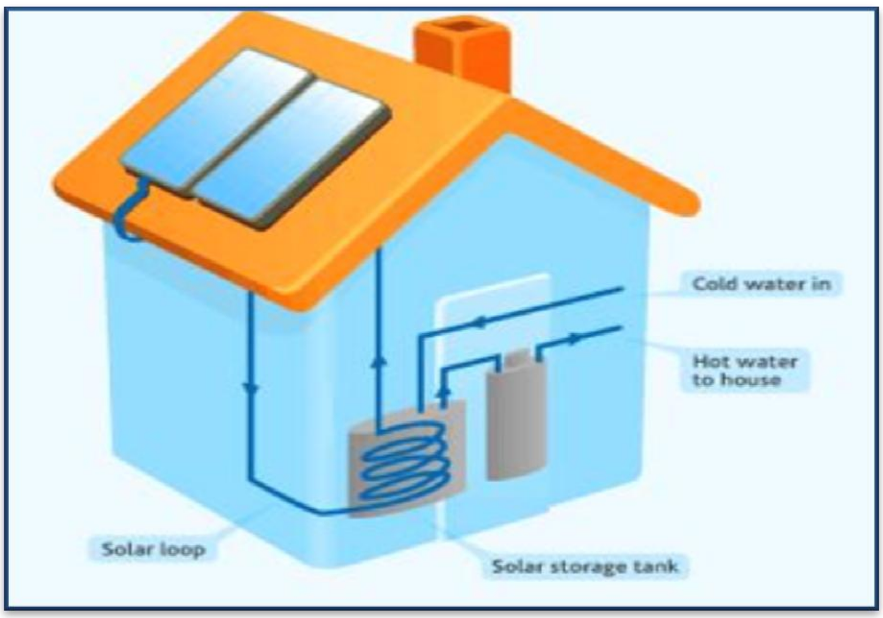
Similar to geo-exchange, these other sources of energy provide either ambient or hot energy to a piping system which contains a liquid that absorbs heat from the surrounding material (sewage, industrial or institutional heat) and delivers it to a central heat exchanger. High efficiency heat pumps convert this energy into hot water or steam contained in a separate piping system that then delivers the heat energy to where it is required for space heating and hot water uses. Centralized equipment is usually contained within a specially designed mechanical room that serves the entire development. The heat exchanger is reversed to provide space cooling, removing heat from the building(s).

Demand for Heat Capture and Exchange is similar to geo-exchange technology.

6.1.3.3 Solar-thermal

Solar-thermal water heating systems, also called solar hybrid water heating systems, are more typically used to supplement conventional gas and electric energy systems that supply Domestic Hot Water ("DHW"), improving the efficiency and lowering the carbon intensity of the conventional systems. A system of solar collection tubes and piping capture heat energy from the sun's rays and deliver it to a central heat exchanger, where it is converted to DHW and distributed in a manner similar to that described above for geo-exchange systems. The solar collection tubes are located outside the building or buildings, typically on the roof, while centralized equipment is again housed in a specifically designed mechanical room. Figure 6-4 below demonstrates how solar thermal systems work.

Figure 6-4: Solar Thermal Systems



Solar-thermal energy systems can be designed in combination with other conventional piped energy systems and metering technologies already a part of the FEU's regulated service offerings. The FEU's expertise with piped energy infrastructure, metering equipment and customer service, combined with the current environmental and social values of customers, make owning and operating these systems an obvious evolution of the FEU's business.

The demand for solar-thermal services comes from owners and/or operators of larger single or multi-use buildings including municipal, institutional, multi-family residential and commercial end users. Such a system or systems primarily serve one or a few buildings, or can act as an input to a larger District Energy System. Both installation and ongoing O&M for solar-thermal systems can be provided either directly by the FEU or through partners such as energy service providers.

6.1.3.4 Biofuels

Biofuels include woodwaste (biomass), animal waste, organic waste and landfill waste. Typically these biofuels are combusted, similar to natural gas, to produce hot water or steam primarily used in district energy systems (although in theory small biofuels are used in discrete systems such as with industrial forestry customers for example). The most common biofuel is biomass (woodwaste). Biomass is generated from urban wood waste, forestry and pulp applications and to a lesser extent from construction wood waste. Biomass is combusted in either wood waste gasification systems or in direct combustion systems. As the combustion of biomass is similar to the burning of natural gas, the thermal energy produced is of a high quality and can be used as hot water or steam, and can also be used to generate electricity in cogeneration plants.

The demand for biomass comes primarily from industrial or institutional anchor customers of a District Energy System. Both installation and ongoing O&M for a biomass system can be provided either directly by the FEU or through partners such as energy service providers.

6.1.4 Natural Gas as Back-Up Fuel

Renewable TES almost always rely on conventional energy systems to provide back-up and peaking energy service. Designing an integrated energy system that can provide 100 percent of peak thermal energy requirements presents both technical and economic challenges. Often, a single renewable energy source such as geo-exchange will be combined with conventional natural gas service. As discussed in Section 2.3, natural gas is efficient, reliable and cost-effective as a back-up energy source. Using natural gas as a back-up energy source and during periods of peak energy requirements improves the economics of the TES overall. Using natural gas in this role also avoids adding to peak electricity demand (which typically occurs in the same timeframe as peak thermal energy demands) which is significant because peak demand is what drives potentially costly system capacity improvements of the electricity system.

6.2 MARKET FOR THERMAL ENERGY SERVICES DEVELOPMENT

The FEU demonstrated through evidence filed in the 2010-2011 RRA that there is widespread customer interest and demand for the FEU providing a broader range of thermal energy beyond natural gas. In this Section, the FEU discuss various customer groups that are driven by different end goals to seek different thermal energy solutions.

Residential and Commercial Developers are driven by their customers' desires and preferences in purchasing a property and paying the on-going costs for energy. Energy choices are therefore dependent upon the marketplace and the end use customer demographic. Lower end residential developments typically use electrical baseboards, whereas mid to higher end developments will use gas and/or other thermal energy solutions. There is a strong desire for products such as geo-exchange and DES in the mid to higher end developments.

Municipalities are seeking to reduce energy usage, to meet provincial GHG emissions reduction targets and to meet their constituents' desires in these areas. Municipalities seek larger solutions such as DES to serve a large group of end use customers.

Institutional entities, such as hospitals and schools, are driven by both energy efficiency (and therefore end use cost) and by the provincial GHG emissions reduction mandates. These entities are seeking solutions that will help them meet provincial obligations and to lower their costs or provide better energy cost certainty.

6.3 THE FEU'S FUTURE ROLE IN DELIVERING THERMAL ENERGY SERVICES

This Section describes the FEU's role in the TES market, and in particular, the nature of the TES services that the FEU are offering to the public. The FEU are able to play a vital role in promoting the use of efficient and "green" TES through a transparent regulated business model that ensures that the customer receives reliable and cost effective service.

6.3.1 Development of Thermal Energy Systems

In this Section, the FEU describe how the Companies can become involved in the development of a thermal energy system. Whether for discrete systems or DES, thermal energy system development generally follows two approaches: the customer/developer seeks out an energy provider to develop their system, or the energy provider develops an opportunity from scratch. The FortisBC companies have been involved in projects that have arisen in each of these ways. In both scenarios, the FEU play a vital role in bringing the project to fruition.

In the first scenario a customer or developer may have an opportunity for a discrete or DES but does not wish to develop the project on their own. The customer will either sole source the opportunity or establish a formal procurement process (such as a RFP, RFEOI or RFQ) to select a proponent to develop the energy opportunity. The energy opportunity and technology can be specified by the customer or the customer may seek the input of the proponent to recommend an energy solution (gas, biomass, geo-exchange etc.). SFU UniverCity is an example of this type of development opportunity. In that case, Corix proposed a biomass energy system and energy solution, whereas other proponents, including the FEU, proposed different energy solutions. To date, FEI has responded to a number of such requests as have Corix and members of ESAC.

In the second approach, the energy provider develops a product from scratch in the hope that there will be interest in the product in the marketplace. Typically this will occur by an energy provider speaking to their customers, and by researching demographic, development and economic trends or opportunities in a particular region. Through these efforts the energy provider may be able to establish an opportunity to build a discrete or DES that it thinks will have market uptake. Delta Schools and the Kelowna District Energy System developed by FEI are examples of this type of approach.

FEI sales staff (termed Energy Solutions staff) serve as the primary contact for customers and potential customers. If through discussions with customers or in the development of an energy opportunity energy sources other than natural gas are or will be required, the Thermal Energy Solutions Staff are engaged[70]. The Energy Solutions staff are responsible for the thermal component of the energy proposal/development. Together these staff respond to Requests For Proposal ("RFP"s) and develop thermal energy proposals and solutions that result in discrete or district energy systems.

From a process standpoint, the following steps are followed when developing or responding to an energy opportunity:

- develop opportunities through customer contact or RFP responses (the two approaches described above);
- sign initial agreements (MOU) with customer;
- determine feasibility of project;
- negotiate/sign binding agreements;
- apply to the BCUC for project and/or rate approval;
- build the energy system; and
- deliver thermal energy.

Throughout this process, the FEU will often be in partnership with, and/or employ the expertise of, Energy Service Companies (often called "ESCOs"), Heating Ventilation and Air Conditioning ("HVAC") providers, and engineering companies in the development of thermal energy systems, and following their implementation, in the operation of these systems. The FEU have used and are using many different engineering consulting firms, ESCOs and HVAC industry organizations in the development of TES projects. The FEU have worked with several member companies of ESAC (which are ESCOs) and are currently partnering with ESAC members on school district projects and DES projects.

This model ensures that the customer, developer, municipality and stakeholders receive the thermal energy solution and service that meets their needs and interests at a reasonable price and with the high degree of transparency that comes with regulation. Due to the complexity of

[70] See Non Rate Base Deferral Accounts (Appendix G) of the 2012-2013 RRA, included in Appendix F of this Submission.

some of these projects, FEI often plays the role of developer/project manager of the proposal, bringing together the expertise from internal FEI groups and external suppliers and providers in order to deliver a successful energy solution. FEI believes that this model for providing thermal energy is appropriate and beneficial for the customer.

6.3.2 Business Models for TES

This Section discusses the various possible commercial arrangements that can be used for the provision of Thermal Energy Service. The first model is the model that FEU will primarily be providing to customers. In Section 6.4.1.1, and summarized in Table 6.1 in that Section, the FEU have addressed the issue of how each of these models is treated under the *UCA* (i.e. regulated or non-regulated).

The following is a summary of six models of commercial arrangements for TES:

1. Utility or ESCO ownership of thermal energy system (the FEU Model)
   - utility or ESCO owns, operates and maintains the thermal energy system;
   - customer purchases thermal energy for own use;
   - customer pays for thermal energy;
2. Utility or ESCO enters performance based contract with customers
   - utility or ESCO operates the facilities that provide thermal energy to a corporation or the public for compensation;
   - customer pays for thermal energy;
3. Customer ownership and operation (equipment purchase only)
   - utility or ESCO installs equipment;
   - customer owns, operates and maintains equipment for the purpose of providing thermal energy to itself;
4. Utility or ESCO provides maintenance
   - customer owns and operates the thermal energy system to provide energy to itself;
   - utility or ESCO maintains thermal energy system through a service contract;
5. Utility or ESCO provides operation and maintenance
   - Customer owns the thermal energy system to provide thermal energy to itself;
   - Customer retains utility or ESCO to operate and maintain thermal energy system under a service contract;
6. Customer purchases system to resell thermal energy

- Customer either owns and operates thermal energy system or just purchases thermal energy from a utility or ESCO.

As described above, the FEU's TES will fall under the first business model. In some of these TES projects, the FEU will be in partnership with, and employ the expertise of ESCOs in the development of Thermal Energy Systems and in the operation of these systems. The FEU have used and are using many different engineering consulting firms, ESCOs and HVAC industry organizations in the development of TES projects. The FEU have worked with several member companies of ESAC and are currently partnering with ESAC members on school district projects and DES projects.

6.4 REGULATORY TREATMENT OF THERMAL ENERGY SYSTEMS

In this Section, the FEU discuss the following regulatory issues regarding TES:

- the reason why TES are regulated under the *Act*, including a discussion of the definition of "public utility", precedents for regulating TES in British Columbia, and the compelling underlying rationale for their regulation;
- that competition among utilities has existed in British Columbia for many years, and is compatible with regulation under the *Act*; how the *Act* recognizes and accommodates the provision of multiple classes of service – in this case natural gas, propane and TES - within a single regulated public utility;
- rate design within the TES class of service;
- why scope of regulation in other jurisdictions (i.e. what is a "public utility") is not relevant in the BC legal framework, but practices used for regulating multiple classes of service in other jurisdictions support the approach being taken by the FEU; and
- that FEU's access to historical natural gas consumption information for some potential TES customer provides little or no advantage to the FEU in the identification and development of TES projects.

These sections demonstrate, among other things, that TES are regulated public utility services in British Columbia, and there are compelling reasons for regulatory oversight of TES by the Commission as a class of service within the FEU. The public interest benefits of TES generally are described in the following section (see Section 6.5).

6.4.1 TES are Regulated under the *Utilities Commission Act*

Thermal Energy Services, when provided by one party to one or more others for compensation, are regulated public utility services under the definition of "public utility" in the *Act*[71]. The logic of regulation is sound in any event. Regulation of TES is both appropriate and necessary because TES are generally complex and costly to operate and maintain, and once installed, the owner or operator has a measure of monopoly power over the customers because there will only be one thermal energy services provider within a certain area, and it is also costly to switch to another energy source. As a result, the customers of these systems have a strong interest in having recourse to a regulator who can ensure just and reasonable rates for the service, and ensure that the service provided is reasonable, safe, adequate and fair[72].

6.4.1.1 Application of Definition of "Public Utility" to TES

Table 6-1 below outlines different business models for the provision of TES, and explains which of the models are regulated on the basis of the application of the definition of "public utility" from the *Act*. The first model in the table below is the one under which the FEU intend to provide TES. The Commission must apply the definition of "public utility", and look to the straightforward application of that provision to determine the scope of its jurisdiction over TES. Table 6-1 should be read in conjunction with the analysis of the definition of "public utility" that is provided in Section 3.

[71] Subject, of course, to the application of any of the exceptions found in the definition of "public utility". There are a number of thermal DES examples in BC that exempt from Commission regulation because they are municipally owned and operated and are within municipal boundaries. For example, the following are exempt DES: Lonsdale Energy Corporation in North Vancouver; Southeast False Creek Neighbourhood Energy Utility in Vancouver; Cheakamus Crossing (Whistler Athlete's Village), and Revelstoke Community Energy Corporation in Revelstoke.

[72] Consider, for example, the supervisory jurisdiction contained in sections 23, 25, 26, 38 and 39. These provisions provide utility customers with recourse to the Commission in the event that a public utility service provider is not providing adequate service, or is unduly discriminating against customers or a particular customer. Absent regulation, customers would be forced to address their concerns through costly and time consuming civil litigation.

Table 6-1: Regulatory Treatment of TES Business Models

Business Model Description	**Ownership**	**Operation**	**Maintenance**	**Compensation from Customer to Utility / Energy Service Company**	**Is the Service Provided by the Utility/Energy Service Company a Regulated Public Utility Service under the UCA?**	**Does the Customer Become a Regulated Public Utility under the UCA?**	**Applicable to FEU?**
1. Utility/Energy Service Company (ESCO) Ownership (Model Used by FEU) Utility/ESCO owns, operates and maintains. Customer purchases thermal energy for own use.	Utility/ESCO	Utility/ESCO	Utility/ESCO	Customer pays Utility/ ESCO for thermal energy.	Yes. The Utility / ESCO is providing a regulated service because the Utility/ESCO is providing thermal energy to a corporation or the public for compensation. Rate schedules should be filed.	No. Customer is the end user.	Yes
2. Performance based contracts Utility / ESCO enters performance based contract with customer under which customer pays for thermal energy, but ESCO shares in operating cost savings as compensation for energy efficiency improvements .	Customer	Utility/ESCO	Utility/ESCO	Customer pays Utility/ ESCO for thermal energy and price to account for a share of operating costs savings.	ESCO operates facilities for the provision of thermal energy to a corporation or the public for compensation. Performance Based nature of contract does not change the fact that customer is paying for thermal energy. Rate schedules should be filed.	No. Customer is the end user.	No
3. Customer Ownership and Operation / Equipment Purchase Utility/ESCO installs equipment, customer owns, operates and maintains for purposes of providing thermal energy to itself only.	Customer	Customer	Customer	Paying for Equipment Only	No. The Utility/ESCO is not providing thermal energy to the public or a corporation for compensation.	No. Ownership and operation for the purpose of self-providing energy is not subject to regulation.	No
4. Maintenance Contract Only Customer owns and operates for purposes of providing thermal energy to itself only. Customer retains Utility/ESCO to maintain though a service contract.	Customer	Customer	Utility/ESCO	Service Contract Fee	No. A maintenance contract is not providing thermal energy to the public for compensation.	No. Ownership and operation for the purpose of self-providing energy is not subject to regulation.	No
5. Operating and Maintenance Contract Only Customer owns for purposes of providing thermal energy to itself only. Customer retains Utility/ESCO to operate and maintain though a service contract.	Customer	Utility/ESCO	Utility/ESCO	Fee for operating and maintenance	It depends. Operating facilities for the purposes of providing thermal energy to a corporation or the public for compensation is regulated. However, it will be a question of fact in each case as to whether the contractual obligations are sufficient to have transferred ultimate responsibility for operation from the customer to the Utility / ESCO.	No. Ownership for the purpose of self-providing energy is not subject to regulation.	Generally not a FEU service
6. Customer Reselling Thermal Energy Customer either owns and operates system or just purchases thermal energy from Utility / ESCO. Customer sells or resells thermal energy to third party/ies.	Either	Either	Either	Either	Either	Yes. By reselling thermal energy to third party/ies for compensation, the customer itself becomes a public utility.	No

As indicated above by the right hand column, the model being pursued by the FEU (model 1) falls within the scope of the definition of "public utility". The FEU believe that the Commission is required to exercise that jurisdiction, although the level of regulation or oversight could vary considerably depending on how much oversight the Commission considers is required.

6.4.1.2 Past Precedent for Commission Regulation of TES

The analysis above is consistent with past precedent. The Commission has been regulating TES as public utility services for many years. Each of the following regulated DES projects are examples of the first business model in Table 6-1 above where the utility owns, operates and maintains the system and the customer purchases thermal energy for their own use. In each case, the provider of these systems obtained a CPCN from the Commission and charges Commission-approved rates.

> **Dockside Green** - The Commission granted a CPCN to the Dockside Green Energy LLP on April 17, 2008, to construct and operate a DES to provide energy service to the Dockside Green development built on the Inner Harbour in Victoria. The facility applied for was a biomass facility to provide hot water heating to the development.
>
> **Corix UniverCity** - Corix Multi-Utility Services Inc. filed an Application for a CPCN to construct and operate an alternative energy-based DES for the UniverCity residential community on Burnaby Mountain. The proposed DES would consist of a production facility and a distribution system. The production facility is planned to be built in two steps: a natural gas fueled temporary Central Energy Plant ("CEP") followed in 2016 by a permanent CEP fueled by an alternative energy source likely to be Biomass. The Commission granted the CPCN for the temporary CEP.
>
> **Central Heat**– Central Heat has held a CPCN since June 11, 1968, which was issued by the Public Utilities Commission to construct and operate a steam generating plant and attendant distribution system for the purpose of supplying steam for heating and cooling uses in the City of Vancouver.

In each of the above cases, it is evident that the Applicants and the Commission took for granted that the system was regulated and required a CPCN and approved rates. For instance, in the recent Corix UniverCity application, there was not a single Information Request inquiring about this issue and no mention of the issue in the Commission's decision granting a CPCN pursuant to section 45 of the *UCA*.

The FEU are also aware of a number of Commission orders involving the sale of thermal energy, which further confirm that the sale of thermal energy in BC as proposed by the FEU is public utility activity. The circumstances in each of these cases involved the sale of thermal energy from an owner of thermal energy producing equipment to another party, and an application by the seller to be exempt from active regulation under the *UCA*. In each case the seller sought and obtained advance approval of the Lieutenant Governor in Council for exemption, and the Commission approved the exemption request. The necessary implication of having to obtain an exemption from regulation is that the sale of thermal energy from one party to another is otherwise regulated. Three examples of such exemptions being granted are:

- Canadian Forest Products Ltd. (BCUC Order No. G-104-04): regarding the sale of steam from its Prince George pulp and paper mill to a neighbouring chemical facility owned by Chemtrade Pulp Chemicals Limited Partnership.

- Al Stober Construction Ltd. (BCUC Order No. G-81-08): regarding the sale of thermal energy from a geothermal energy system (built initially to serve buildings owned by Al Stober Construction and partners) to a nearby strata condominium being developed by Mode Properties Ltd[73].

- Canada Place Corporation (BCUC Order No. G-151-08): regarding the sale of chilled water for cooling purposes to Westbank Projects Corp. for its Fairmont Pacific Rim Hotel and Residences.

6.4.1.3 Regulation and Competition Are Compatible Under the Act

One of the issues raised in prior proceedings regarding the New Initiatives, and which has been raised by ESAC in its Complaint, is the appropriateness of regulating services where competition exists, as opposed to what are often thought of as monopoly services. The FEU provide below information demonstrating the compatibility of competitive market for energy supply and public utility regulation. This issue has a significant legal component as well, but those legal aspects will be addressed in final legal submissions.

The Commission has been regulating multiple providers of TES who compete with each other for customers for some time. Electricity and natural gas utilities are often thought of as natural monopolies by virtue of the fact that it is economic to have only one provider of electricity and one provider of natural gas within a defined geographic area, and it is not economic to have more than one such provider within the same defined geographic area. While electric and natural gas utilities may be thought of as natural monopolies, they nevertheless compete with each other for the provision of energy for heating and cooling applications. In BC, both electric (e.g. BC Hydro) and natural gas utilities (e.g. the FEU) have long offered energy options for space and water heating and cooling, and compete with each other for customers who require these services. In the Vancouver area, a third energy option for heating applications has existed alongside electricity and natural gas for some time. Central Heat (steam) operates a

[73] Plans were subsequently changed and Al Stober Construction did not proceed with the proposed sale of thermal energy so the exemption was later rescinded by BCUC Order No. G-139-08.

TES in the same geographic area (downtown Vancouver) as BC Hydro (electricity) and FortisBC Energy Inc. (natural gas).

The fact that BC Hydro, Central Heat and FEI have long competed with each other in the thermal energy market has not precluded the Commission from regulating all three entities' provision of energy in Vancouver. Before an energy system is installed in a particular building or area there are several possible ways to meet the thermal energy requirements and there is competition among the providers of competing energy forms to meet the thermal energy demand. Once a customer has selected a particular thermal energy source, however, that customer is essentially captive to the service provider because of high costs of conversion to another energy source. There is also likely to be only one option for each energy type within a particular area (e.g. one electric utility, one natural gas utility, and one steam utility). This makes the Legislature's decision to impose regulation on such systems an entirely reasonable one. Just as customers who have chosen natural gas or electricity for space heating (for example) have a strong interest in having their service overseen by a regulator, so to do customers who have chosen a TES. The TES customer has the same interest in having recourse to a regulator who can ensure that they receive reasonable, safe and adequate service, at just and reasonable rates, as do natural gas and electricity customers[74].

Further information on electricity, natural gas, propane and thermal energy providers in British Columbia is included in Appendix A.

6.4.1.4 Prior Regulatory Treatment of Discrete Systems within FortisBC Alternative Energy Services Inc.

Prior to 2010 a number of TES projects were developed by FortisBC Alternative Energy Services Inc. ("FAES", formerly Terasen Energy Services). These projects have not been actively regulated by the Commission up to now. Since January. 1, 2010, the TES previously offered by FAES are now being done through FEI as approved by the FEI 2010-2011 RRA NSA[75]. FAES has not applied to the Commission for approval of the rates for the contracts that were in place prior to January 1, 2010[76]. The degree of regulation of these systems is not unreasonable given the relatively small scale of the services to date. However, the absence of active regulation does not in any way mean that the service is not and has not been public utility service under the *UCA*.

---

[74] See the *Act,* sections 24-26 and 37-39 for example.
[75] Order No. G-141-09, dated November 26, 2009, included in Appendix H.
[76] FEI has stated in the regulatory proceeding for the 2010 Long Term Resource Plan (Exhibit B-10, Response to BCUC IR 2.6.1, included in Appendix F of this Submission) that it is actively considering bringing the pre-2010 FAES contracts into FEI and filing them with the Commission for acceptance as a rate. It is FEI's intention to file these with the Commission in due course.

As discussed in Section 2.2, as government policy has shifted strongly in the direction of energy efficiency and conservation and towards reducing GHG emissions in BC the market is now beginning to advance for thermal energy service. In this context it is appropriate for the Commission to now take a more active role in the regulation and oversight of this service. As such, FEI will be filing each of its new contracts (i.e. those established in 2010 and after) with the Commission for acceptance as a rate, irrespective of their size. Since each project has been or will be developed using an economic test that is consistent with the test provided in the 2010-2011 RRA (FEI Tariff, GT&C Section 12A[77]), these contracts should satisfy the Commission requirements under Order No. G-141-09 and the *UCA*. Since the projects are economic as per the test, it is reasonable to expect that they will recover their cost of service over their economic lifespan including an amount for the New Energy Solutions Deferral Account and an amount for recovery of overhead allocation of the entire public utility.

6.4.2 Provision of TES as a Class of Service within the Utility

In this Section, the FEU describe how the Companies intend to provide TES as a regulated class of service within the existing regulated utility (FEI) according to the rate constructs established in the 2010-2011 RRA NSA, and why this is in the interests of customers. In order to provide the relevant context for this discussion, the FEU first apply some factual context to the legal discussion in Section 3 (Legal Framework) about how the *Act* contemplates that regulated public utilities can and will offer multiple classes of service. The FEU also discuss below how various public utilities in this province have provided and continue to provide multiple classes of service within a single corporate entity.

6.4.2.1 The Act Contemplates the Single Utility Model

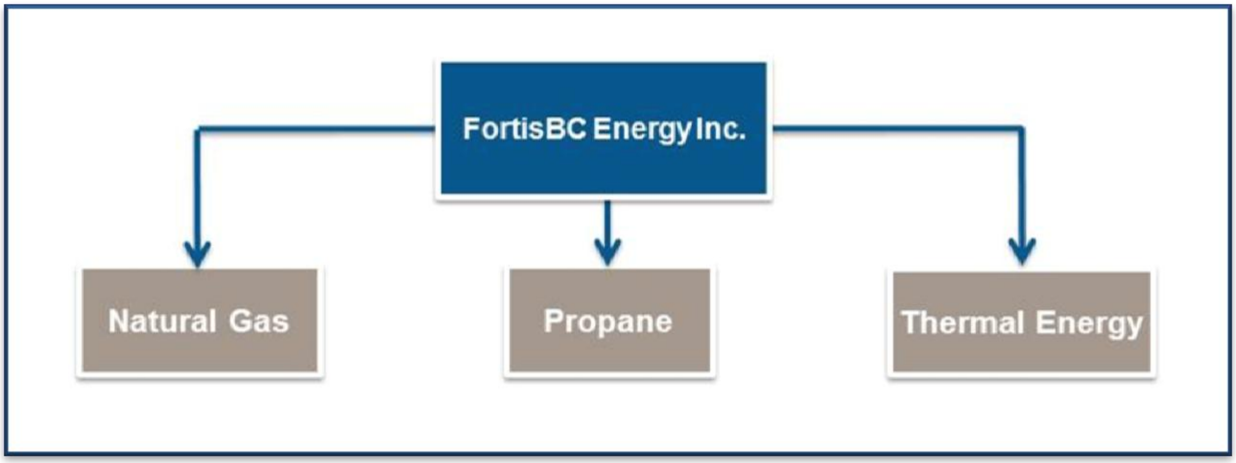
The FEU's model for providing TES involves the existing regulated utility providing the services as a distinct regulated class of service. As described in Section 3, sections 21 and 60 of the *UCA* contemplate the regulation of multiple "classes of service" within a single utility, kept distinct for ratemaking purposes. The use of this model by public utilities in British Columbia is well established. In addition to the 2010-2011 RRA NSA, which expressly contemplated that TES be treated as a separate "class of service" according to the *UCA*, there have been other examples, outlined below, of a public utility offering different regulated classes of service over the years.

THE FEU ALREADY OFFERS MULTIPLE CLASSES OF SERVICE

As depicted in Figure 6-5 below, prior to the addition of the TES class of service to FEI in the 2010-2011 RRA, FEI already offered natural gas service and propane services. FEI has offered propane service in Revelstoke since the system was constructed (by BC Gas) in 1990.

[77] GT&C Section 12A is included in Appendix F.

Figure 6-5: FEI Offers Various Energy Forms As Classes of Service

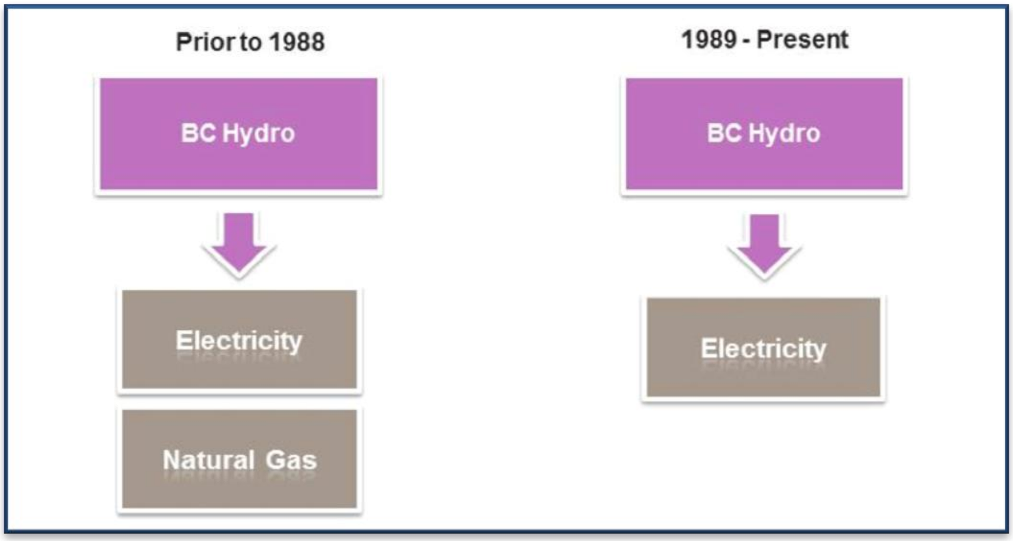


While not a separate class of service, it bears noting that Ft. Nelson operates as a distinct operating area within FEI, with its own rate base and rate structure. Cost allocation is undertaken in much the same manner as is being undertaken for the thermal energy class of service and Ft. Nelson derives similar benefits from the shared structure.

BC HYDRO AND POWER AUTHORITY OFFERED ELECTRICITY AND NATURAL GAS

As depicted in Figure 6-6 below, prior to 1988 BC Hydro had both gas and electric classes of service. In 1988 BC Hydro sold its Gas Division which distributed natural gas in the Lower Mainland and has since only provided electricity to its customers. The BC Hydro Gas Division was sold to Inland Natural Gas. The combined gas entity became BC Gas Inc., and after a number of reorganizations and name changes it has become FortisBC Energy Inc.

Figure 6-6: BC Hydro Offered Both Gas And Electric



CORIX MULTI-UTILITY SERVICES INC. OFFERS MULTIPLE SERVICES

Corix Multi-Utility Services Inc. ("Corix" or "CMUS") employs a variant of the single-utility model in British Columbia and elsewhere in Canada.

As implied by its name, "Corix Multi-Utility Services Inc." offers multiple services (e.g. water, wastewater, gas, electricity, thermal energy, etc.) within a single entity. Corix's letter of intervention in this proceeding describes itself as providing "multi-utility services, including alternative energy services". Corix similarly described itself as follows in its recent SFU UniverCity CPCN Application:

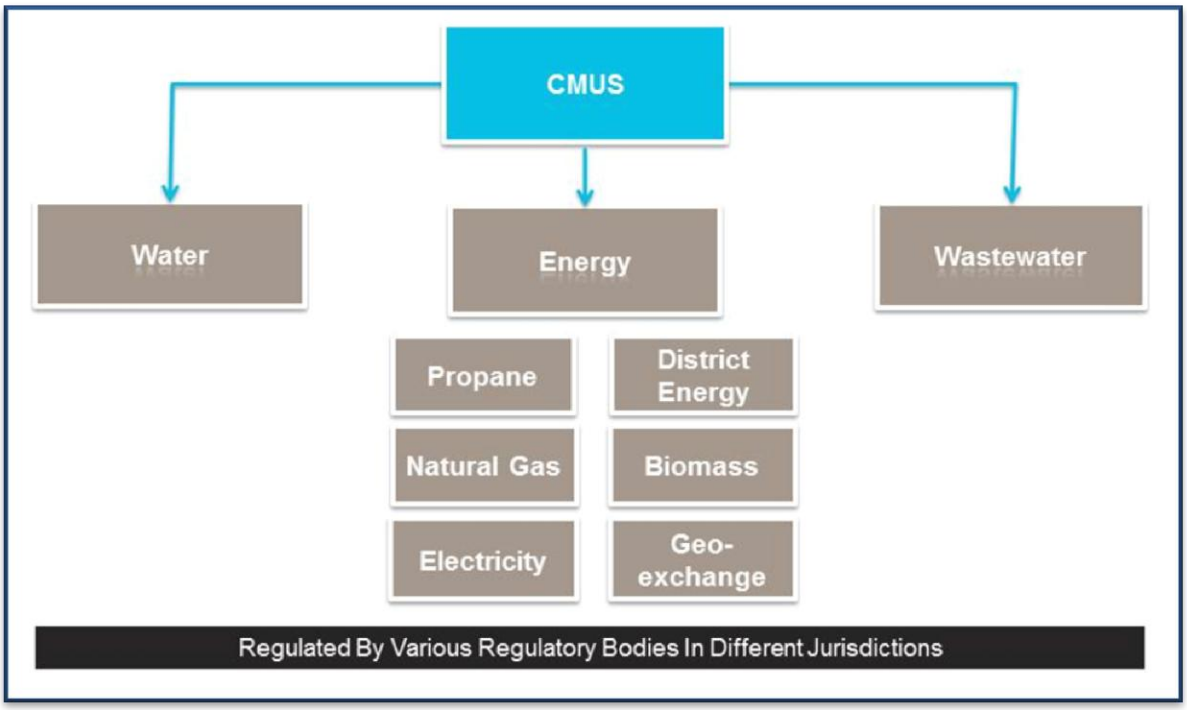
> *"Corix Multi-Utility Services Inc. ("CMUS"), a subsidiary of Corix Utilities Inc. ("Corix"), is a company incorporated under the laws of the Province of British Columbia, registration number BC0560353. CMUS's business address is Suite 1160, 1188 West Georgia Street, Vancouver, BC, V6E 4A2.*
>
> *CMUS provides multi-utility and energy utility services to customers across Canada and manages a portfolio of utility systems that are regulated by the provincial regulatory authorities."* [78]

Corix provides a number of utility services in various communities in BC, some of which are regulated by the Commission and others of which are not.

[78] Corix UniverCity CPCN Application, Exhibit B-1, Section 2.1.

The FEU understand the regulatory and business model employed by Corix to be that depicted in Figure 6-7. That is, Corix has multiple service offerings within different service areas, and within its energy service offering it provides various forms of energy. Those energy forms may be regulated or not depending on the various legal and regulatory frameworks in the different jurisdictions in which it operates.

Figure 6-7: CMUS Has Multiple Service Offerings



In the Corix application for a CPCN for the UniverCity project it indicated that Neighbourhood Utility Service ("NUS") would be owned and developed by Corix[79].

6.4.2.2 Benefits of the Single Utility/Multiple Classes of Service Approach

Cost efficiencies and regulatory efficiency are two reasons why the single utility/multiple classes of service model is the FEU's preferred approach and why it is in the public interest to make utility investments in TES in this manner.

First, there are cost efficiencies that benefit both natural gas customers and TES customers. On the gas side, customers benefit from shared overhead costs. Having the TES class of service within the same utility as the natural gas class of service results in sharing of overhead

79 Corix UniverCity CPCN Application, Exhibit B-1, Section 2, p. 8.

costs in the same way as is done among FEI, FEVI and FEW. In the long-run, the more successful the TES business becomes, the greater the potential benefit for the FEU's natural gas customers in terms of the recovery of overheads and common costs from the TES customers.

Efficiencies benefit the TES customers as well. FEU staffing efficiencies can be realized in finance, accounting and administration as employees have the training and expertise to administer the TES class of service efficiently within a single regulated entity. There are also efficiencies in terms of fewer contracts to establish and administer if all the necessary operating services are within the utility so that outside services do not have to be contracted for independently. Ultimately, the TES customers benefit from these efficiencies, where rates are cost of service based.

Corix has recognized that there are cost efficiencies to be achieved when multiple utility operations are provided through one corporate entity. In the response to BCUC IR 1.2.1 in its recent UniverCity DES application, Corix stated that the UniverCity NUS received services from Corix and this was a decided advantage:

> *"Dockside Green was a partnership between several entities and therefore required the establishment of a separate utility. As a small utility operation, Corix believes that CMUS is the appropriate ownership structure for the UniverCity NUS because this will allow the utility to use established resources for both administration and operations."*

The FEU believe that the same logic articulated by Corix should apply in the case of the FEU.

Second, there are also regulatory efficiencies. The Commission has previously acknowledged that, generally speaking, it is best to avoid the proliferation of a number of regulated utilities within the same group of companies. In the Gateway Lakeview Estates CPCN Decision (December 14, 2006) the Commission stated that:

> *"Certainly, it is likely to be less efficient and more costly from the Commission´s perspective to regulate a number of small utilities, rather than one larger utility serving the same customers. Going forward, the Commission expects TES and TGI to consider and address this concern when they are developing plans to serve new developments and groups of customers that are in or near TGI´s service area. The Commission is not certain that a proliferation of small, but related utilities, all under the same parent, TI or KMI [Kinder Morgan Inc., which at the time was the ultimate owner of the Terasen Utilities], is necessarily in the public interest."*

Gateway was a propane system. In order to move it within FEI as the Commission appeared to suggest in the above quoted decision, Gateway would have had to operate as a separate class of service within the utility. By the same logic, it makes sense to bring what would otherwise be small thermal utilities within the FortisBC group under the framework of a thermal class of service within the existing utility.

6.4.2.3 Cost Allocation is Key to Offering Multiple Classes of Service

The proper allocation of costs is key to the effective offering and regulation of multiple classes of service. The FEI 2010-2011 RRA NSA stipulates that the costs of developing thermal energy systems will be recovered from TES customers. The customer or group of customers for a particular TES project will have a separate cost of service, rate or rates and, if applicable, contribution calculation. Having separate rates and cost of service for the TES class of service protects natural gas customers and leads to just and reasonable rates for both gas and alternative energy customers.

The starting point in rate setting for multiple classes of services is section 60 (1) (c) of the *Act*, which sets out the requirement to set rates separately for distinct classes of service. It states the following:

> *(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.*

Further legal discussion regarding "classes of service" is set out in Section 3. In meeting the requirements of *UCA* section 60 (1) (c) the FEU's approach will be to fairly allocate cost among classes of service in a transparent manner that is subject to review in regulatory proceedings. The cost allocation process for TES is described in detail in FEU's 2012-2013 RRA (Appendix G), included in Appendix F of this Submission. There are three main categories of costs that are allocated to the TES class of service: (1) the direct costs of projects, (2) sales, marketing and business development O&M costs, and (3) an overhead allocation, which is currently $0.5 million annually (which reduces rates for natural gas service). The standard allocation approaches between regulated activities such as the Massachusetts model would yield very little allocation to TES class of service at this early point in its development, and therefore the methodology adopted by the FEU is most appropriate[80]. The details of the costs allocations to TES for 2012 and 2013 are being addressed in the FEU 2012-2013 RRA proceeding.

The transfer pricing model has been used in BC to establish the appropriate rates and cross-charges for utility staff and resources being utilized in affiliated non-regulated businesses ("NRB"s). Since the FEU's TES initiatives will all be regulated activities the use of a transfer pricing policy approach based on NRB use of utility resources is not appropriate. The FEU's approach of using a shared services approach to allocate corporate overheads and common costs between classes of service and using established utility resources and expertise in the

80 Please see the response to Corix IR 2.3.1 in the FEU 2012-2013 RRA proceeding, included in Appendix F.

operation and management of both classes of service is the best model to achieve economies of scale and provide benefits to both classes of service.

6.4.3 TES Rate Design

Order No. G-141-09 approved Section 12A, "Alternate Energy Extensions" of the FEI Tariff General Terms and Conditions. Section 12A (a copy of which is attached in Appendix F) sets out the basis for the rates that FEI will charge customers for TES services. We discuss the rate design inherent in the approved GT&Cs below.

Section 12A provides considerable flexibility to address unique circumstances, but within defined parameters that will be common to all projects. A certain degree of flexibility is beneficial, particularly in the early stages of TES development. TES projects will be tailored to particular customer needs, and as a result, the cost inputs will vary between projects and service agreements will tend to have different language and provisions to reflect the unique circumstances of each project. In addition, based on varying project costs, end use rates will be different from one installation to the next. Therefore, for every TES project, the Company will develop a service rate based upon Section 12A, and the parameters outlined in the economic assessment model (discussed below), as a Tariff supplement.

Section 12A of the GT&Cs requires the FEU to undertake an economic assessment of "alternative energy extensions" (i.e. TES). To that end, for each geo-exchange, solar-thermal and DES system, FEU will conduct an economic assessment using a cost of service ("COS") analysis using accepted COS modeling practices in BC and will set customer rates on a project by project basis to recover each project's cost of service over time.

One of the hurdles of adopting low carbon emitting alternative energy systems is the high up-front capital costs. Typically the full costs of a new DES or alternative energy system occur right after the system comes into service. However, the customers that will use the system are added over time. In the absence of rate smoothing or deferral mechanisms the initial customers will have very high energy bills, and subsidize the customers who attach in later years.

Levelizing the rate and allowing inflation-based rate increases over a longer period, such as twenty years, provides a balanced solution to this issue and will promote adoption of TES[81]. A long-term levelized approach (in the range of 15 to 25 years) yields a service rate that will incent customers to attach to a DES system in the early years and support the reduction of GHG emissions. Even under a rate levelizing approach annual revenue and cost imbalances will occur over a project's life. Deferral accounts will be used to address imbalances and provide customers with competitive rates and maintain utility returns on investment at allowed levels.

[81] A levelized rate methodology has been proposed and approved in both the Dockside Green and SFU UniverCity DES projects.

Such mechanisms, if needed, will be part of the project evaluation and included with the contract filing.

The economic assessment models used to determine customer rates for Thermal Energy Services will be based on accepted utility practices in BC for determining revenue requirements and designing rates.

For discrete projects, the customer pays for the system equipment and operation over time at a rate per unit of energy (or on a flat monthly charge basis) comparable with conventional systems, but avoids a portion of the conventional commodity cost.

For DES, the system replaces the need to purchase, operate and maintain expensive equipment within each building as well as avoiding a high proportion of the commodity costs for conventional energy. Again, the customer has full knowledge of the available alternatives and the costs and benefits of the district energy system. In this case the customer chooses what may be a higher cost, more complex design in order to better meets their needs and objectives for a renewable, low carbon energy system. For this system, the customer pays in rates for the capital carrying costs of the system equipment, an alternative fuel source commodity (wood waste) and system operation and maintenance over time at a rate per unit of energy. In these examples, the customer has chosen the energy system with full access to information on the costs and benefits of available alternatives and has chosen a system that best fits their needs. The customer pays for the system and its operation over time at a rate that is acceptable to them, and fair to other customers.

6.4.4 Regulatory Approaches in Other Jurisdictions

The Commission's issue 2(c) from the Scoping Order asks about the regulatory treatment of AES in other jurisdictions. The scope of regulation in other jurisdictions turns on the unique provisions of the regulatory legislation in each jurisdiction. However, the FEU are consistent with general principles applied across jurisdictions of allocating costs and ensuring just and reasonable rates in circumstances where there are multiple classes of service.

With respect to the scope of regulation, there have been, for instance, information requests in the 2012-2013 RRA about the scope of regulation in Ontario. However, the Ontario Energy Board Act ("OEBA") and the *UCA* are decidedly different in how they regulate thermal energy services. The OEBA sets out defined regulation for electricity producers and natural gas transmitters and distributors, but does not cover thermal energy service. In contrast, as discussed above, the definition of "public utility in the *UCA* captures thermal energy service. The Ontario Energy Board ("OEB") considers "green energy initiatives" that involve the production of "renewable energy", such as TES, to be unregulated and allowed to develop in a competitive market environment[82]. The important fact, however, is that the Ontario legislative framework permits the OEB to take that view. The FEU understand that TES are not actively regulated in certain other jurisdictions in Canada as well, such as Alberta and Quebec.

The FEU have attached a report on TES in other jurisdictions prepared by EES Consulting. This report is found in Appendix F. The EES Consulting report demonstrates that the model adopted by the FEU of having two regulated classes of service is within the range of models adopted elsewhere. EES Consulting is of the view, as experts in rate design and cost allocation, that the regulatory mechanisms in place to allocate costs are appropriate.

6.4.5 Information sharing within FEU

The FEU's access to the consumption information of its natural gas customers has been raised as an issue by ESAC in the 2012-2013 RRA proceeding. The FEU's access to market sensitive information is also noted at several points in the the Commission's Scoping Order (Exhibit A-5) and Issue 2(d) in Appendix A of the Scoping Order raises the question of what conditions should govern the FEU's providing of market sensitive information to *non-regulated* businesses that are related or unrelated businesses. Since the FEU's TES offerings will all be regulated business Issue 2(d) is not relevant to sharing gas consumption information between two classes of service within the FEU. Beyond this however, the discussion below addresses the limited value of having access to historical natural gas consumption information.

Historical natural gas billing data is general information of limited value in assessing and developing a thermal energy system.

- First, historical information does not exist for new construction.
- Second, the historical natural gas billing data includes the total gas consumption at the meter which may or may not be the natural gas consumption needed only for the production of the thermal energy that will be replaced by the thermal energy service. A customer's gas usage may include consumption for activities unrelated to the requirements of a thermal alternative energy system, such as for example, cooking in restaurants or institutions, or commercial process load.
- Third, natural gas may not be the only energy source used by a customer in the generation of thermal energy so historical natural gas consumption may be only part of the picture. Consequently, it is not possible to understand whether historical natural gas billing data equals the natural gas consumption that was necessary for thermal energy production or whether other energy sources are involved, without an evaluation of the specific equipment and usage requirements of the customer at the site over time.

[82] See OEB Decision EB-2009-0172, pages 5-6.

- Fourth, the type, nature, and location of the heating and cooling equipment systems in buildings may or may not be compatible with thermal energy solutions. Therefore, FEI database of historical natural gas billing data alone is not an effective tool for identification of marketing opportunities for TES in the absence of the accompanying technical evaluation by site.

As such, natural gas consumption history is not used by FEI to market thermal energy systems.

Evaluation of a TES project usually requires a feasibility analysis that specialists perform. These experts may request and review historical natural gas billing information in the process of performing their technical evaluation.

In the event that FEI is not the TES service provider, but is the natural gas service provider, a simple request by the customer to FEI to share the historical natural gas billing data at their site with the proponent to assist in their technical evaluation is all that is required. Alternatively, many customers keep records of their consumption data and may actually provide the information to the proponent on their own, without the assistance of FEI.

In the event that FEI is the TES service provider and the natural gas service provider, no formal request is necessary on behalf of the customer for its personnel to utilize the historical billing data in the evaluation of the project. This is because the Thermal Energy Service is simply another class of service within the public utility, not a separate entity. Nonetheless, since this type of information would only be useful in conjunction with the technical evaluation of the project, customers expect FEI to review their historical billing data at that stage. Interestingly, for expediency, many customers actually provide this information to FEI since they often have it readily at hand.

At all times, FEI maintains conformance with the *Personal Information Protection Act*.

6.5 FEU'S PARTICIPATION IN THE TES MARKET SUPPORTS PUBLIC INTEREST

In this Section, the FEU describes five key reasons why adoption and provision of TES by the FEU responds to the key drivers identified in Section 2 and is in the public interest. In particular, the FEU's involvement in TES:

- provides an option for new and existing customers that wish to adopt lower carbon energy sources to meet their thermal energy requirements;
- confers benefits on natural gas customers;
- promotes "British Columbia's energy objectives";

- helps mitigate FEU's growing business risks from declining load in the natural gas class of service, assisting the FEU to remain financially healthy and able to serve the public good in the provision of thermal energy solutions to BC consumers in the long run; and

- enhances the growth and development of the TES market, promotes energy choice for consumers, and expands the opportunities for ESCOs and other market participants in the provision of these services in British Columbia.

Each of these is further discussed below.

6.5.1 FEU's TES Provides Options for Customers that Wish to Adopt Alternative Energy Solutions

As discussed in Section 3 (Legal Framework), the Commission's consideration of customer interest must assess the benefits to existing and future TES customers, not just natural gas customers. The FEU's TES provides an option for new and existing customers that wish to adopt lower carbon energy sources to meet their thermal energy requirements.

Also, as discussed in Section 2.4, customers and customer interest groups have indicated the desire for greener energy alternatives and meeting this demand is in the interests of customers. The FEU's involvement in TES ensures that we meet the demand for clean, low carbon, efficient, renewable energy sources while helping customers meet their GHG emissions reductions requirements.

The Commission, in its decision in the FEI's and FEVI's System Extension and Customer Connection Policies Review (dated December 6, 2007), has acknowledged that meeting these customer interests is in the public interest:

> *"the public interest can be served by an environment in which customers in the province have the right to choose their fuel source; in which the cost consequences of their choice are transparent; and where rate design does not hinder that choice*."

6.5.2 Benefits Conferred Upon Natural Gas Customers

Making TES available as a class of service also can confer benefits on natural gas customers by retaining natural gas as a back-up service and also sharing common costs.

As stated in Section 2.1, the FEU have faced and will likely continue to see declining throughput, attributable in part to declining use per customer rates, which increases upward pressure on delivery rates and also represents a long-term stranding risk for the distribution system assets as a whole. By offering TES backed by natural gas, the FEU will help ensure that natural gas remains a part of the energy picture for many years to come. Retaining some natural gas throughput from back up demand will mitigate the adverse delivery rate impact on natural gas customers flowing from declining throughput associated with the customer shift to alternative forms of energy because those customers could otherwise have turned to a system backed by electricity (with no natural gas).

The FEU allocated $500,000 in each of 2010 and 2011 to TES, which would otherwise have been recovered from natural gas customers. The same allocation is proposed for 2012 and 2013. As the TES business grows, it is logical to expect that the allocated amount would grow as well.

6.5.3 FEU's TES Supports British Columbia's Energy Objectives

As stated in Section 2.2, "British Columbia's energy objectives" are defined in s. 2 of the *Clean Energy Act* ("*CEA*") and apply to FEI as a public utility. The applicability of "British Columbia's energy objectives" to applications for approval under various sections of the *UCA* speaks to the Government's intention to use cost-effective investments by public utilities to help achieve targeted reductions of GHG emissions, greater energy efficiency, and other public policy goals.

Table 2.7, in Section 2.2.6.3, outlines how TES is consistent with and conforms to "British Columbia's energy objectives". One of the energy objectives is "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". The FEU's TES initiatives encourage the use of clean, low carbon, and renewable energy sources in BC. Furthermore, the energy objectives encourage efficient use of energy and the switching from one kind of energy source or use to another in order to reduce GHG emissions. The development and use of geothermal, solar and district energy solutions is carbon neutral. Their use of these energy sources in place of a carbon positive energy source, such as natural gas, will lead to reduced GHG emissions in BC.

Finally, the FEU's TES contribute to economic development and foster significant relationships and partnerships in the communities. The FEU has actively pursued stakeholder consultation activities, including workshops, presentations to municipalities and customers, website communications, and focused meetings with select stakeholders seeking input on a range of regional and provincial energy issues and solutions. TES require partnerships with many stakeholders, including customer organizations, government agencies, municipalities, First Nations, as well as private sector, industry and market participants, trades, manufacturers, NGOs, advocacy groups and other utilities, promoting economic activity and social development. Generally, the stakeholders have been supportive of the FEU's approach to becoming a fully integrated energy utility and expressed that it makes sense to develop TES as part of service offerings. Therefore, the FEU's involvement in TES serves the interests of society as a whole and the broader public interest is served by regulatory processes that are aligned with government's efforts and policies, all of which are in favour of efficient energy use and lower carbon energy forms as part of the solution to addressing climate change and reducing GHG emissions.

6.5.4 FEU's TES Mitigates Business Risks

As stated in Section 2.1, the FEU's pursuit of TES is a positive contribution to managing long term business risks that arise from declining throughput levels on the natural gas system. New Initiatives mitigate such business risks and ensure that the FEU will be able to recover its investments in rate base over time and achieve its allowed return. The shareholder's interest in a healthy utility are aligned with the customer interest.

6.5.5 FEU's TES Creates Market Development Opportunities

The FEU's view is that the Commission's ability to consider the impacts of the FEU's participation in TES on competition is limited to the impact on customers, and not the competitors. There are other agencies that regulate fair trade practices. However, two points bear mention that do not come out in the letters filed by Corix and ESAC.

First, the Commission oversees rates, and determines whether they are just and reasonable based on the factors identified in the *UC*A. The FEU's rates for TES are cost of service based, which necessarily precludes so-called "predatory" or below-cost pricing. Just and reasonable rates can support fair competition *indirectly* by ensuring that the FEU's services reflect the true costs of providing the service. It would not be just and reasonable to charge a rate to FEU's TES customers that is more than a fair and reasonable charge for the service provided in order to permit other competitors with a different cost of service to improve their market position.

Second, while competitors will generally favour excluding a competitor from the field, there is a potentially favourable impact on ESCOs of the FEU's involvement in the TES business. The FEU's participation in the market has already provided important business opportunities for ESAC members. The FEU are currently working with several ESAC members on potential TES projects for school districts and municipalities. The more rapid deployment of TES in British Columbia spurred by the involvement of public utilities will in turn expand the market for ESCOs to sell their services and equipment in the province. Thus ESCOs will also benefit from the FEU's (and other utilities') involvement in TES.

6.5.6 Summary: Public Interest Met

The FEU's TES is aimed at meeting customer expectations for lower carbon energy solutions, and is aligned with provincial policy. By meeting the needs of customers, the initiative is also in the interest of the shareholder. Together, these considerations speak to the FEU's ongoing investment in TES being in the public interest.

6.6 PROPOSED GUIDELINES FOR TES

The FEU's participation in TES is responsive to customer demand, provides benefits to existing and future natural gas and thermal energy customers, and advances government's policy objectives. The FEU have proposed guidelines that, if adopted, will provide greater clarity about how the FEU's involvement in Thermal Energy Services can be done in a manner consistent with the public interest and maintaining just and reasonable rates for the natural gas and TES classes of service.

The FEU propose the following guidelines for the Commission's public interest evaluation of TES projects:

Interests of Ratepayers

1. When the Commission evaluates a TES project, a consideration of the interests of ratepayers involves a consideration of:

    (a) customers of the natural gas class of service;

    (b) the potential TES customer(s) who will receive service from the TES project; and

    (c) other TES customers within the TES class of service that share with the TES project the common costs of the TES class of service.

2. With respect to the interests of natural gas customers:

    (a) The interests of natural gas customers are protected through the application of appropriate cost allocation methodologies and through the segregation of the two classes of service (i.e. natural gas and TES) as required by the *UCA*, with TES costs of service being recovered from TES customers.

    (b) Natural gas customers benefit from an allocation of indirect/overhead costs to TES, which would otherwise be recovered in natural gas rates.

    (c) Natural gas customers benefit from additional gas throughput associated with a TES project that incorporates natural gas as part of the energy solution. Considerations relating to the load-factor associated with such natural gas load, and how that drives capital investments in natural gas facilities, should be addressed through FEI's Phase "B" Rate Design Application that will occur in 2012 and other future rate design applications over time.

3. With respect to the interests of the specific customer that wishes to adopt thermal energy service:

    (a) The TES customer is making a choice:

(i) to have a thermal energy system in place of natural gas service, electricity, or some other fuel alternative; and

(ii) to work with FEI as its project partner.

The TES customer has an interest in the Commission giving effect to that choice.

(b) TES customers of a specific TES project should pay a rate that recovers the direct project-specific costs over the life of the project and its portion of the allocated overhead and business development/sales costs.

(c) TES customer of a specific TES project should not pay for costs associated with the natural gas class of service, except to the extent those costs result from natural gas being incorporated into the project. These costs would be derived under existing natural gas rate schedules.

4. With respect to the interests of the customers of the TES class of service generally:

(a) TES customers generally should contribute through their rates to the recovery of the balance in the Thermal Energy Services Deferral Account, which reflects common costs, overhead and sales/marketing costs, business development costs of providing TES service.

(b) TES customers should not pay for costs associated with the natural gas class of service, except to the extent that they are also natural gas customers.

5. When properly applied by FEI, rates for TES service based on FEI's GT&Cs, Section 12A, and other rate constructs established in the 2010-2011 RRA proceeding:

(a) adequately protect the interests of customers of FEU's natural gas class of service;

(b) generate cost of service based rates for TES; and

(c) allow for a TES project rate to recover a portion of costs from the Thermal Energy Services Deferral Account.

Interests of Competitors

6. Potential TES customers will have a range of considerations, desires, and preferences in selecting a TES provider (such as the FEI, Corix or ESAC members). As a non-regulated entity, the TES customer should be left to determine the nature of, or manage, the selection process it undertakes.

7. The Commission's interest in competition is related to concerns about whether the competitive market place best serves customers through, for instance, competitive pricing. The Commission has no general mandate to oversee competition, increase competition or to favour one market participant over another.

8. The FEU are entitled to use their own corporate strengths to compete for TES customers to the extent lawfully permitted by competition and consumer protection legislation[83].

9. In circumstances where the potential TES customer has selected FEI as its project partner, evidence of the existence of another third party alternative provider of TES would only be given weight in the public interest assessment of the FEU's TES project if the third party provider files evidence to establish that the interest of the TES customer in accessing service from FEI as its preferred partner at regulated rates is outweighed by a long-term benefit to customers generally that flows from overriding the specific customer's preference.

<u>Interests of Broader Public (generally) and furthering British Columbia's Energy Objectives</u>

10. The FEU collectively serve at least half of British Columbians, and there is thus considerable overlap between the interests of customers and the interests of British Columbians generally.

11. British Columbia's energy objectives, which must be considered in the context of public interest assessments under sections of the *UCA* applicable to TES, are an expression of the broader public interest. The public interest is also informed by other expressions of government energy policy.

12. A TES system that reduces GHG emissions and/or provides economic benefits is in the interest of British Columbians generally.

13. The adoption of a TES, as opposed to electricity, for heating load can reduce cost pressure on the electric system due to avoidance of high cost supply and potentially capacity-driven infrastructure. Since most British Columbians require electricity service regardless of whether they use electricity for heating purposes, any potential savings of this nature is relevant to the broader public interest.

[83] The FEU's position is that Commission-approved cost of service rates for TES that are consistent with the *Act*, by definition, cannot be predatory.

The Rights of the Utility Shareholder

14. Under the *UCA*, the shareholder's interest is in earning a fair return on, and return of, its invested capital. To that end, as recognized in the Commission's past cost of capital decisions, TES rates must provide the FEU with an opportunity to earn a fair return on, and return of, its invested capital in TES projects.

15. The shareholder has an interest in finding ways to combat declining natural gas use rates, which represents a challenge to its ability to recover its capital invested in natural gas assets over time. TES that incorporate a natural gas component assists in this regard to the extent that the customer might otherwise adopt a thermal energy solution that does not incorporate natural gas.

Please refer to Section 8 for additional guidelines regarding TES regulatory process.

7 DISPENSING ENERGY EFFICIENCY AND CONSERVATION INCENTIVES TO CUSTOMERS

Since the 1990's, FEI and FEVI have been involved with Demand-Side Management activities, which the FEU refer to as Energy Efficiency and Conservation activity. EEC activity is sanctioned under the *UCA*, and brings value to customers by helping them to reduce their energy bills through energy efficiency and conservation. In the process of delivering benefits to customers, EEC activity also advances the Province's policy goals of reduced GHG emissions, the efficient use of energy and energy conservation.

The ESAC Complaint raised the issue of how EEC funding is dispensed to thermal energy customers. EEC incentives are currently delivered to customers via prescriptive programs focused primarily on the upgrade of specified equipment such as boilers, water heaters or spray valves. TES is not a target of these programs. The Companies' involvement with the Public Sector Energy Conservation Agreement ("PSECA")[84] represents FEU's first foray into providing incentives via a performance-based "custom" funding model whereby an incentive is provided based on $5/GJ saved, regardless of the equipment installed. The fact that this program is not specific to a particular technology means that it is possible to apply it to a thermal energy system. To date, however, the only thermal energy customer to have also applied for an EEC incentive (via the provincial governments PSECA program) is the Delta School District ("DSD")[85]. The FEU have requested EEC incentive funding, in the concurrent 2012-2013 RRA proceedings, for the Thermal Energy for Schools Program, which would target schools with the objective of encouraging the schools to adopt efficient thermal energy systems. At this time, however, there are no EEC programs dedicated specifically to thermal energy customers.

In this Section, the FEU address the principles that are, and should be, applied in dispensing EEC funds to all customers, including customers implementing thermal energy projects. The existing principles and procedures applied by the FEU in the dispensing of EEC funds are consistent with industry practice. They ensure that once a program is developed that contemplates the provision of incentives to customers interested in implementing high-efficiency thermal systems, all customers interested in adopting high-efficiency thermal energy systems have equal access to EEC funds, regardless of whether the customer decides to engage the FEU or a third party, such as Corix, to own and operate the thermal energy infrastructure. As such, the FEU believe that the Companies' existing principles and procedures continue to be

[84] The PSECA Initiative is a program designed to encourage reduced natural gas consumption in public sector buildings by operating in partnership with the Government of British Columbia's Public Sector Energy Conservation Agreement.

[85] The FEU have also corresponded with the Central Okanagan School District specific to one school about the provision of an EEC incentive under the Commercial Custom Design program, which is described on pages 86 – 89 of the 2010 EEC Annual Report, and included in Appendix G to this Submission. The Companies expect the School District to apply for the incentive.

appropriate. The FEU have proposed guidelines in Section 7.6 and Section 8 that reinforce the current equitable approach to dispensing EEC incentives.

This Section is organized as follows:

- Section 7.1 describes EEC funding and explains how it advances the public interest;
- Section 7.2 summarizes the main elements of the established EEC framework, and explains why this Inquiry should consequently focus on how funds are dispensed to customers, including those natural gas customers that are interested in thermal energy;
- Section 7.3 provides a description of FEU's EEC programs related to thermal energy projects;
- Section 7.4 explains why the current principles and procedures applied by the FEU in the dispensing of EEC funds generally ensure that all customers have equal access to EEC funds where the criteria are met, and this applies equally to customers interested in thermal energy;
- Section 7.5 demonstrates that the FEU's practice for dispensing EEC funding is consistent with industry practice; and
- Section 7.6 proposes guidelines for the Commission which are common to industry practice, and which reinforce the equitable approach currently applied to dispensing funds.

7.1 EEC IN CONTEXT

This Section describes EEC programs and explains how, in general, they advance the public interest. As addressed in prior applications, the FEU's EEC programs, funding requests, and use and dispensing of funds benefit customers through energy savings in efficient end-use applications, as well as through the efficient use of FEU's energy resources and delivery systems. They are aligned with British Columbia's energy objectives, government policies, as well as DSM Regulation requirements.

7.1.1 EEC Defined

Simply defined, EEC activity refers to activities designed to affect customers' use of energy – either through reducing their consumption of natural gas, or through promotion of load management, fuel switching, or demand response. The term EEC is intended to be synonymous with "demand-side measures", which is a defined term in the *UCA*. The FEU are developing EEC programs that are aimed at providing customers with incentives for the adoption of efficient thermal energy technology. Ultimately, the EEC portfolio, and the savings they can achieve, are considerations in the utilities' long term resource planning[86].

The definition of "demand-side measure" in the *UCA* refers to the *CEA* where the term is defined as follows:

> *"Demand-side measure" means a rate, measure, action or program undertaken*
> *(a) to conserve energy or promote energy efficiency,*
> *(b) to reduce the energy demand a public utility must serve, or*
> *(c) to shift the use of energy to periods of lower demand,*
> *but does not include*
> *(d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or*
> *(e) any rate, measure, action or program prescribed;*

EEC activity aims to encourage the most efficient use of natural gas in end-use applications, inducing market transformation over the medium to long term, ultimately easing the adoption of more stringent energy efficiency standards and regulations by the Provincial government.

EEC funding includes monetary incentives for customers who meet the specific DSM/EEC program criteria, and non-incentive costs for things such as the development of an EEC program. EEC programs provide incentives to customers to alter their behaviour or adopt more efficient technologies in order to reduce the customers' natural gas consumption. The customers availing themselves of the incentives and reducing their consumption can ultimately reduce their overall energy costs. EEC costs are recovered in the delivery rates from all of the FEU's natural gas ratepayers, who as a group can avail themselves of the incentives and programs intended to help them reduce the amount of energy or commodity they require. EEC activity is within the natural gas class of service, even where the funds are being applied to a thermal energy project, because the EEC funding is promoting conservation and/or the efficient use of energy[87].

The Commission's recent NGV-EEC Decision[88] determined that incentive funding directed at encouraging heavy-duty vehicle fleets to adopt NGV instead of diesel is not a "demand-side measure" within the meaning of the *Clean Energy Act* and the *UCA.* The Commission's decision focused on the elements of the "demand-side measure" definition and identified the requirement for the incentives to be directed at "conservation" or "energy efficiency". The Commission stated that the definition of demand-side measure is clear in that it relates to the use of "energy" itself and not the infrastructure used to deliver it. The Commission reasoned

86 Section 44.1 of the *UCA* contemplates, in effect, that utilities will identify as part of a resource plan the steps they are taking to reduce demand.

87 Please see the response to Corix IR 2.5.13 in the 2012-2013 RRA proceeding, included in Appendix G.

88 Order No. G-145-11, dated August 15, 2011, included in Appendix H.

that NGV engines convert energy at a lower rate than diesel engines, and thus are less "efficient", despite their green attributes. The FEU believe that when the logic of this decision is applied to incentives directed at thermal energy, the outcome is that the initiatives should result in either conservation or reduced energy requirements to meet the same load requirements in order to meet the definition of "demand-side measure". The "green" attributes of thermal energy, which are referenced in "British Columbia's energy objectives", are considered only once the incentive has qualified under the definition of "demand-side measure" and do not themselves form the primary justification for the incentive programs. The FEU intend to apply this analysis in developing programs directed at thermal energy and in determining the eligibility requirements for such programs.

7.1.2 How EEC Advances the Public Interest

The FEU's EEC programs have been successful in promoting conservation and the efficient use of natural gas, which in turn reduces energy costs for customers, while supporting government policy by reducing GHG emissions.

As indicated above, EEC programs offer customers access to a wide variety of energy efficiency and conservation incentive programs, assisting them to reduce energy consumption. Natural gas commodity costs represent a significant portion of utility rates at the burner tip. Therefore, despite the cost of EEC programs being recovered in natural gas delivery rates, customers who avail themselves of EEC programs are able to lower their energy consumption, and thus their overall energy bills. Cost-effective DSM can also avoid higher energy acquisition costs and capacity-driven infrastructure investments that cause upward pressure on delivery rates.

A key aspect of the public interest assessment, however, is that the customers' energy savings can also be accompanied by a reduction in the individual and societal impacts associated with conventional energy use. Government policy and direction has responded to climate change concerns and utilities are being encouraged and directed to invest more resources into energy efficiency and conservation activities in order to meet GHG emissions reduction objectives. EEC activities are, in part, a response to direction signalled by government in, notably, the 2007 BC Energy Plan, the *CEA* and the *UCA.* These policies reinforce the concept that utilities such as the FEU should take a leading role in these activities. Customers trust and look to utilities such as the FEU for information and support for the most appropriate ways to use energy. As stated in Section 2.2, the FEU's EEC activities and programs support government policies and are aligned with British Columbia's energy objectives as set out in the *CEA.*

The Commission's reasoning in the NGV-EEC Decision highlights a qualitative distinction between EEC and the other New Initiatives and how they promote the public interest. Although EEC typically advances "green" policy objectives, the GHG emissions reductions are a byproduct of the efficiency and conservation efforts aimed at helping customers reduce their energy (commodity) requirements and avoiding the need to acquire higher cost energy supply. The Biomethane Service, CNG/LNG Service, and TES all involve the provision of energy at a regulated rate. These three service offerings achieve the "green" policy objectives by providing options for customers to use "the right fuel, for the right activity, at the right time" – an important energy efficiency objective expressed in the BC Energy Plan. The Commission's NGV-EEC Decision makes clear that "the right fuel, for the right activity, at the right time" is not the type of energy efficiency that is at play in the definition of "demand-side measure". Despite the different approaches, all of the New Initiatives named above play an important role in advancing the public interest.

7.1.3 Summary: EEC Has Role in Advancing the Public Interest

In summary, the FEU's EEC activity, including the potential use of EEC funds for thermal energy related projects in the Province, provides financial, social, and environmental benefits to customers (and society as a whole) by reducing customer energy costs, stimulating economic development and local job opportunities, and reducing GHG emissions.

7.2 THE EEC FRAMEWORK IS WELL ESTABLISHED THROUGH PAST DECISIONS

FEI and FEVI have been involved in EEC activities since the 1990s. The current overall EEC framework was approved in the EEC Decision in 2009[89]. This included accepting a funding envelope, approving program areas, approving the portfolio approach to assessing the cost effectiveness of the initiatives, establishing the test by which the portfolio is to be evaluated and endorsing accountability mechanisms. The framework has since been considered in other regulatory proceedings, such as the 2010-2011 RRA and the NGV-EEC Incentives Application. This Section summarizes the main elements of the established EEC framework. Given the well-established nature of the framework, and the fact that aspects of the framework are being considered in the current 2012-2013 RRA proceeding, this Inquiry should focus on how funds are made available to natural gas customers that are interested in thermal energy.

7.2.1 Funding Envelope and Cost Recovery

The EEC framework involves the FEU obtaining advance acceptance of EEC funding as a section 44.2 expenditure schedule. The Commission has also established cost recovery mechanisms for expenditures included within those schedules.

In years prior to the FEI and FEVI's 2008 EEC Application, FEI's EEC funding levels were established at approximately $1.50 million per year for incentives and approximately $1.624 million per year for non-incentive expenses. FEVI had EEC expenditures of approximately $650,000 per year for incentives, plus $500,000 per year for non-incentive costs. Historically, FEVI's DSM activities were aimed at employing marketing programs to attract new customers and add load in order to improve the utilization of the gas delivery system on Vancouver Island.

[89] Order No. G-36-09, dated April 16, 2009, included in Appendix H.

Recognizing that a higher level of funding was required to expand EEC initiatives in order to deliver additional cost-effective programs to customers and bring value to stakeholders, FEI and FEVI collectively filed their EEC Application in 2008, seeking approval of increased funding of EEC programs for the timeframe of 2008-2010. The Commission's EEC Decision approved funding in aggregate of $41.5 million ($34.4 million for FEI and $7.1 million for FEVI). FEI and FEVI are allowed to recover EEC related costs from all customers, to capitalize the approved EEC expenditure to a regulatory deferral account, and to amortize deferral account balances for a period of up to ten years.

Further, FEI and FEVI applied in their respective 2010-2011 RRAs for additional funding for 2010 for Interruptible Industrial customers and for Innovative Technologies[90], and for funding for the overall EEC portfolio for 2011. On November 26, 2009, the Commission released Orders No. G-141-09 and G-140-09 approving Negotiated Settlement Agreements ("NSAs")[91] in the 2010-2011 Revenue Requirement Applications for FEI and FEVI respectively. The NSAs allocated a further $32.35 million in EEC expenditures for FEI, and $6.1 million for FEVI, to bring the total approved EEC expenditure to 2011 for both utilities to approximately $80 million. The Commission-approved NSAs re-affirmed the cost recovery mechanisms established in the EEC Decision. As stated in the NSAs approved by Orders No. G-141-09 and G-140-09:

> *All agreed to EEC expenditures will be considered and evaluated within the existing portfolio, and be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 514, Item 6).*

In the concurrent FEU 2012-2013 RRA, the FEU are applying for EEC funding for 2012 and 2013. The FEU have stated an intention in that proceeding to bring forward future EEC requests in the context of the Long Term Resource Plans (the next Long Term Resource Plan is expected to be filed in 2013). The FEU have also proposed changes to the cost recovery mechanisms, including a revised financial treatment of EEC spending that protects ratepayers in the event that the Companies are unable to spend the full amount within the funding envelope. Under the proposed financial treatment, only $20 million per year of EEC spending is reflected in the 2012-2013 rate base and revenue requirements. Actual EEC spending in 2012 and 2013 above $20 million per year will be recorded in a non-rate base deferral account (attracting AFUDC) and will not commence recovery in rates until 2014. This revised financial approach is intended to ensure that customers only pay for actual EEC expenditures that are incurred during 2012 and 2013.

---

[90] **Innovative Technologies** are best described as market ready technologies that have little or no market penetration in the BC energy efficiency landscape. They can be defined as emerging and/or enabling technologies. Some of these technologies include, but are not limited to, solar thermal DHW systems, GSHPs, hydronic systems, sterling engines, micro co-generation, natural gas transportation, and fuel cells. Hydronic systems can be classified as enabling technologies as they have the flexibility and potential to receive future energy from District Energy Systems. The Commission has since concluded in the NGV-EEC Decision that NGV related incentives do not fall within the "Innovative Technologies" program area.

[91] Order No. G-141-09 and G-140-09, dated November 26, included in Appendix H.

The approach the FEU have employed in securing funding through expenditure schedules is contemplated in Section 44.2 of the *UCA*. The *UCA* also requires that the FEU be able to earn a fair return on its expenditures, and this is reflected in the established EEC framework approved by the Commission, as well as the modifications to the cost recovery mechanisms being proposed in the 2012-2013 RRA.

7.2.2 Approved Program Areas

The funding requests have been for an overall funding envelope, but the FEU have identified certain program areas that define the scope of the expenditure schedule being approved by the Commission. Approved EEC program areas to date include Residential, Commercial, Joint Initiatives, High Carbon Fuel Switching, Conservation Education and Outreach, Affordable Housing, as well as Industrial and Innovative Technologies. The Commission has expressed that the design of EEC programs is reasonable, flexible and in the public interest, and accepted the expenditure proposals for these program areas in both the 2008 EEC Application and 2010-2011 RRA. Table 7-1 below summarizes key elements of the existing EEC framework with respect to development of new programs *within* the approved Program Area in order to optimize the overall portfolio.

Table 7-1: EEC Framework for Program Areas

Annual Funding Envelope						
Program Areas Scope of Expenditure Schedule Approval Defined by Expressly Approved Program Areas						
Residential	**Commercial**	**High Carbon Fuel Switching**	**Conservation for Affordable Housing**	**Innovative Technologies**	**Joint Initiatives**	**Industrial**
Programs or Initiatives The FEU has flexibility to develop programs or initiatives within approved Program Areas and reports in the EEC Annual Report and EEC Stakeholder Committee meetings						
ENERGY STAR® Heating System Upgrade	Spray N'Save 2010 Program*	Switch 'N' Shrink	REnEW*	Solar Water Heating PSECA Program	LiveSmart BC	Energy Audit Funding Agreement*
Furnace Service "TLC"*	Efficient Boiler Program		Energy Savings Kit*	Solar Air Heating PSECA Program	Washer Rebates*	Heat Exchanger Program*
Domestic Hot Water Heaters	Light Commercial ENERGY STAR® Boiler Program		Ministry of Energy Low Income Partnership Grant	SolarBC Schools Incentive	City of Vancouver Weatherization*	
EnerChoice Fireplace	Efficient Commercial Water Heater Program					
	Energy Assessment Program					
	PSECA Initiative*					
	Fireplace Timers Pilot*					
	Radiant Tube Heaters Pilot*					
	Spray N'Save Program*					
	Commercial Custom Design Program*					
*Indicates the program was added after the NSA s(G-140-09, G-141-09) This table does not show the Conversation Education and Outreach Program Area Programs "in development" are not included in list of programs and initiatives						

7.2.3 Cost-Effectiveness Test and Portfolio Approach

As per the EEC Decision, the Commission approved the Total Resource Cost ("TRC") test to be the appropriate test for cost effectiveness and accepted using the TRC test at the Portfolio level to evaluate EEC programs. In its EEC Decision[92], the Commission, on page 32, stated:

---

[92] Order No. G-36-09, included in Appendix H.

> *"The Commission Panel accepts the portfolio level approach based on achieving a portfolio TRC level, discussed below, of 1.0 or greater provided that program areas, initiatives or measures with an individual TRC of less than 1.0 are proactively designed and sufficiently support social or environmental objectives".*

Rather than evaluating cost-effectiveness on a program-by-program basis, the portfolio approach to cost-benefit analysis means that the overall EEC portfolio must maintain a TRC ratio of 1.0 or higher.

Furthermore, the Commission-approved NSAs for FEI's and FEVI's 2010-2011 RRA re-affirmed the approach established in the EEC Decision. As stated in both NSAs approved by Orders No. G-141-09 and G-140-09:

> *"All agreed to EEC expenditures will be considered and evaluated within the existing portfolio, and be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 514, Item 6). However, Innovative Technology programs will be managed by [FEI and FEVI] as a separate segment of the overall portfolio to have a weighted average Total Resource Cost ("TRC") of 1.0 or more. [FEI and FEVI] will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee."* [93]

7.2.4 Accountability Mechanism

FEI and FEVI proposed EEC accountability mechanisms in the EEC Application proceeding as follows:

> *"In this Application the Companies have recognized the need for accountability for the funds approved for EEC programs. First, any funds not spent will not be charged to the regulatory asset deferral account. Second, the Companies intend to monitor the portfolio TRC on a monthly basis, and have proposed to file an Annual EEC Report with the Commission by the end of the first quarter every year. The Report will detail program activity, expenditures, and cost-benefit results for the previous year, as well as describe program activity and provide forecasts for the upcoming year. Third, in the event that the relief sought is granted, the Companies would form and engage an EEC stakeholder group with membership representing a broad cross section of stakeholders identified in the Application. Fourth, the Companies have indicated their intention to hold annual EEC workshops with stakeholders, at which the Companies would present updates on program progress and obtain stakeholder input on new programs and refinements to existing programs. Fifth, the Companies are proposing to develop many of the programs*

[93] Order No. G-141-09, Appendix A, page 6, and Order No. G-140-09, Appendix A, pages 8 and 9 (see Appendix H)

for the commercial sector and the DSM for Affordable Housing sector in conjunction with stakeholder advisory groups." [94]

In the EEC Decision, the Commission accepted the accountability undertakings and directed that the annual EEC Report include the following:

- *TRC, RIM, UC, and Participant test calculations of DSM at the Program Area initiative and individual measure levels in addition to the total Portfolio level reporting. Reporting of the Residential & Commercial EE program areas should also be made at the New Construction and Retrofit levels.*
- *any inter and intra Program Area initiative funding transfers, with supporting rationale, and the impact of such transfers on the transferor and transferee Program areas, initiatives, and measures as the case may be.*
- *data for fuel switching programs should be tracked in a manner which allows for reporting types of fuels replaced by natural gas, including estimated GHG impacts.* [95]

The Commission also directed FEI and FEVI to include in their annual EEC Report to the Commission a discussion of their internal data gathering, monitoring and reporting control processes.

The 2009 and 2010 EEC Annual Reports included a transparent comprehensive overview of the FEI and FEVI's EEC initiative for those two years.

The Commission-accepted accountability undertakings included formation of an EEC Stakeholder Group with membership representing a broad cross section of stakeholders as well as semi-annual EEC workshops with stakeholders, at which the Companies present updates on program progress and obtain stakeholder input on new programs and refinements to existing programs. As an illustration of the breadth of the consultation that occurs in this context, Corix and members of ESAC were invited to participate:

- On November 13, 2009, an email and invitation was sent by the FEU to a number of potential participants, notifying those potential participants of the formation of the EEC Stakeholder Group, of its purpose, and inviting them to participate. This email and invitation are provided in Appendix B. It should be noted that ESAC member Direct Energy received this email invitation, as did Mr. Ron Cliff, the signatory of the ESAC complaint letter, and Mr. Ken Donison of Corix.

---

[94] FEI-FEVI EEC Application, final Argument Submissions, page 39,
[95] Decision and Order G-36-09, date April 16, 2009, page 42 (see Appendix H)

- ESAC member Trane is represented on the FEU's EEC Stakeholder Group by the General Manager of National Energy Equipment, Trane's exclusive dealer in British Columbia for residential products.

ESAC's statement in its letter of complaint dated April 27, 2011 that "*neither ESAC or its members were included in the EEC Advisory Group*" is inaccurate. ESAC members were invited to participate in the EEC Stakeholder Group. Other EEC Stakeholder documentation, including presentations and minutes from the meetings were included in the 2009 and 2010 EEC Annual Reports.

7.2.5 Summary: EEC Framework is Well Established

The past decisions referenced above have established a workable EEC framework to be used going forward. As a result, this Inquiry should be focussed on how EEC incentives are dispensed, in response to the ESAC and Corix complaints. Those complaints focused on the incentives available for thermal energy systems, which are discussed immediately below.

7.3 EEC INCENTIVES RELATED TO TES AND NEW INITIATIVES

At the time of writing, there are currently no EEC programs intended specifically to support the highly efficient thermal energy projects that are the subject of this current proceeding. The Companies provided EEC funding to one Thermal Energy Services customer, the Delta School District ("DSD"), under the Public Sector Energy Conservation Agreement[96] initiative. The Efficient Boiler Program ("EBP") could also be used by customers installing high efficiency thermal energy systems. The Companies have also almost completed program design on a Custom Design Program ("CDP"), which could potentially be used by customers installing the kind of high efficiency thermal systems that are the subject of the current proceeding. Funding approval for a "Thermal Energy for Schools" program has been requested in the FEU's 2012-2013 RRA, but has not yet been approved, therefore program design, which would include the determination of program terms and conditions to which a customer would have to conform in order to receive an incentive under a future program, has not yet been completed. The PSECA initiative, the EBP, the CDP, and the potential future Thermal Energy for Schools program are described below.

7.3.1 Public Sector Energy Conservation Agreement Initiative

Full details of the Companies' PSECA Initiative can be found on pages 74 to 77 of the 2010 EEC Annual Report, included in Appendix G to this Submission. Generally speaking, the

[96] The PSECA Initiative is a program designed to encourage reduced natural gas consumption in public sector buildings by operating in partnership with the Government of British Columbia's Public Sector Energy Conservation Agreement.

PSECA initiative was implemented to encourage reduced natural gas consumption in public sector buildings, and it was operated in conjunction with the Climate Action Secretariat, which had $25 million available in capital grants to provincial government facilities. All PSECA participants, including Delta School District, submitted an application and detailed energy study first to the Climate Action Secretariat, who determines which provincial applicants would be eligible for provincial funding from the province's $25 million PSECA capital grant program. The Climate Action Secretariat then forwarded successful applicants for its capital funding to the FEU and to BC Hydro for those latter two entities to determine whether any incentives from the FEU's EEC program and from PowerSmart could be contributed to these public sector building upgrades, in addition to the capital grant the province was making available to PSECA program applicants. Including Delta School District, the FEU's PSECA initiative issued funding commitments to 10 different organizations for energy efficiency upgrades at 35 different public sector building locations. To date, Delta School District is the only customer to have applied for an EEC incentive in addition to engaging the services of the TES class of service within FEI[97].

7.3.2 Efficient Boiler Program

Full details about the EBP can be found on pages 54 to 59 of the 2010 EEC Annual Report, included in Appendix G to this Submission. The Efficient Boiler Program is the Companies' flagship commercial program. It is a prescriptive program, providing incentives to customers that install condensing- or near-condensing boilers. Customers submit a "pre-approval" application form, install eligible equipment, submit a "post-approval" application form and receive an incentive.

7.3.3 Custom Design Program

Information about the CDP can be found on pages 86 to 89 of the 2010 EEC Annual Report, included in Appendix G to this Submission. At the time the report was written, program design for the CDP had not yet been completed, however that work has now been done, and information about the CDP is available on the Companies' website. The program provides a non-prescriptive incentive of $5/GJ conserved by an energy efficiency measure, or a combination of measures, including those measures that make use of alternative energies with gas backup. It is conceivable that the high-efficiency thermal energy systems that are the subject of the current proceeding could qualify for an incentive under the CDP, however of the five applications to the CDP that customers have submitted to the Companies, none of the customers are proposing to install the kind of high-efficiency thermal systems that are the subject of this proceeding.

[97] The FEU have also corresponded with the Central Okanagan School District specific to one school about the provision of an EEC incentive under the Commercial Custom Design program, which is described on pages 86 – 89 of the 2010 EEC Annual Report, and included in Appendix G to this Submission. The Companies expect the School District to apply for the incentive.

7.3.4 Thermal Energy for Schools

The FEU have proposed an EEC incentive program for up to 260 schools over 2012 and 2013 in the 2012-2013 RRA. Information about this proposed program can be found on pages 14 to 15 of Appendix K-1 to the 2012-2013 RRA, included in Appendix G to this Submission. School districts operate in a challenging environment where they must reduce GHG emissions without increasing operating costs and in the absence of access to sufficient capital to employ lower emission technologies. It is the objective of the proposed Thermal Energy for Schools Program to enable school districts to conserve energy and improve energy efficiency in their buildings, while also reducing GHG emissions in a cost-effective manner, using the best fitting technology solution by site, and to achieve these benefits within existing operating budgets and capital constraints for the entire school district. The technology options might include geo-exchange, high efficiency natural gas boilers and/or other technologies such as enhanced controls. As the proposed Thermal Energy for Schools program has not yet been approved, the FEU's EEC team has not yet commenced program design for Thermal Energy for Schools, which would include the development of the terms and conditions for a Thermal Energy for Schools program, however as with all the Companies' EEC programs, all customers that comply with the terms and conditions of a potential future Thermal Energy for Schools program would receive an incentive, regardless of equipment ownership.

7.3.5 Summary Regarding Thermal Energy Related EEC Programs

As can be seen from the information provided in Section 7.3.1 above, the FEU have provided funding to date to only one Thermal Energy Services customer, the Delta School District, through the PSECA initiative. The FEU subsequently describe how they do and will adhere to the principle of universal access with respect to dispensing all EEC funds.

7.4 THE PROCESS FOR DISPENSING EEC INCENTIVES, INCLUDING FUNDS FOR TES PROJECTS

This Section focuses on the issue of the use and distribution of EEC incentives. The current procedures applied by the FEU in the dispensing of EEC funds, which are premised on the principle of universality, generally ensure that all customers have equal access to EEC funds where the criteria are met. This applies regardless of whether the FEI or some other third-party like ESAC or Corix is selected by the customer to provide the thermal energy services.

7.4.1 Universality

The FEU's EEC activity complies with the requirements for adequacy as laid out in the DSM Regulation and is guided by the "EEC Program Principles" put forward originally in the 2008 EEC Application, which, among other things, included the following key principles:

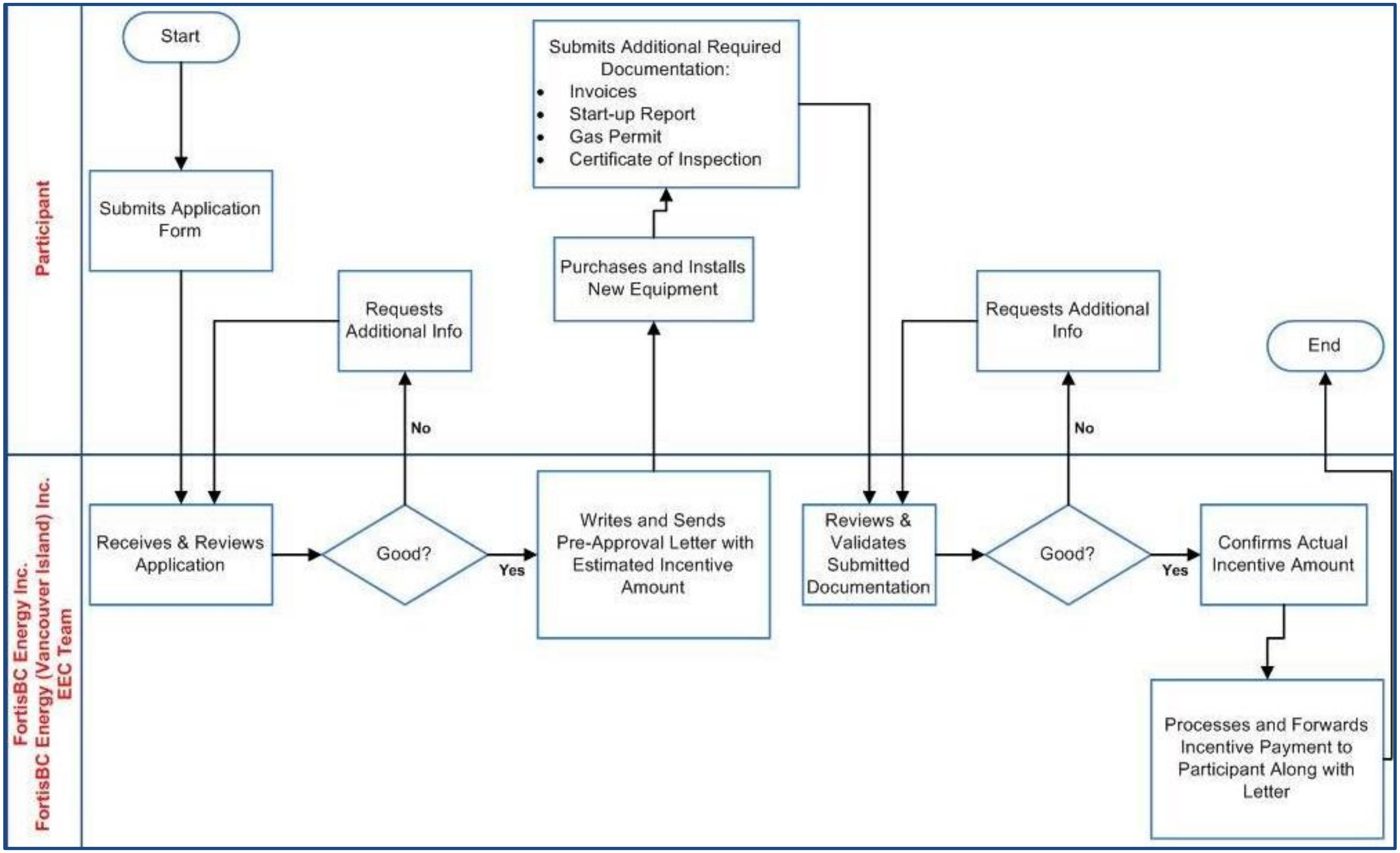
1. *Programs will have a goal of being universal, offering access to energy efficiency and conservation for all residential and commercial customers, including low income customers through the DSM for Affordable Housing initiative.*

2. *Wherever possible, programs will be uniform, so that customers in one part of the service territories of the Terasen Utilities have access to the same programs as customers throughout the service territories.*

The portfolio of EEC programs is presented to the EEC Stakeholder Group Members for their input and feedback twice yearly, and is also presented in the EEC Annual Report. As indicated previously, these two Commission-approved accountability mechanisms offer a method by which stakeholders can provide feedback to the FEU regarding the EEC programs. Program results for the previous year and high-level program plans for the upcoming year are presented in the March meeting, and more detailed program plans for the upcoming year are presented in the November meeting. Highly detailed program information including program budgets for both the year previous and the upcoming year is published in the Companies EEC Annual Report, filed by March 31 every year. Feedback is solicited from the EEC Stakeholder Group at the meeting, and circulated to the group after the meeting. Material related to the EEC Stakeholder Group activity in 2009 and 2010, including all presentations and member feedback are filed with the 2009 and 2010 EEC Annual Reports.

Each program has its own distinct set of eligibility criteria, terms, conditions and program process. Figure 7-2 below provides an example of a standard prescriptive program process that participants must pass through in order to secure an EEC incentive.

Figure 7-2: EEC Incentive Process



Funding is available to all customers within FEI and FEVI service areas, subject to each program's eligibility criteria, terms and conditions. These eligibility criteria, terms and conditions are established by EEC staff, and ensure that incentives are delivered only within the program's intended context and objectives, thereby helping to ensure that EEC expenditures are cost effective. The FEU EEC program incentives will be available to program participants regardless of whether they choose to retain full ownership of their energy systems, use a third party to manage their system operations, or fully divest such ownership in favour of an energy services contract with a third party of their choice[98]. In all such cases EEC incentives are offered to customers to reduce the cost and thereby encourage the selection of high efficiency alternatives. BC Housing, for example, has used Amaresco (an ESAC member) as their energy services company and has received many thousands of dollars in Efficient Boiler Program incentives in recent years. Incentives are available to building developers in the case of new construction, or owners or long term lease holders in the case of existing buildings.

Potential program participants may speak with the Companies sales staff to obtain information about any of the actively running incentive programs; however, to receive funding they must forward an application for the appropriate program to the Companies' EEC staff. The duties and functions of the FEU's EEC staff was discussed in the response to Corix IR 2.5.13 in the FEU's 2012-2103 RRA proceeding, included in Appendix G to this Submission. EEC staff receive EEC program applications, input data for program tracking, validate submitted information, and guide participants through the application process via on-going telephone support where and when necessary. Generally speaking, third party reviewers are contracted in some cases to validate natural gas savings claims on either an aggregate, annual basis (such as with the Efficient Boiler Program) or on an individual project basis (such as with the PSECA Initiative). Once a participant has satisfactorily fulfilled all the program's requirements, the EEC staff confirms and issues the appropriate incentive amount, as determined by the program parameters. Only EEC staff members have the authority to determine incentive amounts and approve funding from the EEC budget; the Companies' Sales and Thermal Energy Services staff (who are tasked with marketing thermal energy services to customers) do not have the authority to determine incentive amounts and approve funding from the EEC budget.

The Companies are committed to strong internal controls vis-à-vis the operation of the EEC program, as outlined in the EEC Application proceeding. Ensuring that the programs are available to all qualifying potential participants and that all applications are compliant with program requirements is an important part of EEC's internal control process. Our business practices related to program development, application processing, and ongoing monitoring and reporting are all sound and subject to continuous improvement. As with all grants or incentives made available in the form of DSM or EEC programs, the customer has a role to play in accessing and meeting the requirements of the program to qualify for these funds, before the funds can be dispensed[99].

---

[98] Please see the response to BCUC IR 1.204.3 and Corix IR 2.5.2 in the 2012-2013 RRA proceeding, included in Appendix G.

[99] Please see the response to ESAC IR 2.6.6 in the 2012-2013 RRA proceeding, included in Appendix G.

7.4.2 PSECA Funding to Qualifying Customers

The EEC funding for thermal upgrade projects at schools in the DSD will be delivered via the Companies PSECA Initiative (which was summarized above and is described in detail on pages 74 to 77 of the 2010 EEC Annual Report, included in Appendix G to this Submission). As mentioned before, to date, DSD is the only customer to have applied for an EEC incentive in addition to engaging the services of TES class of service within FEI[100]. As with all other participants in the PSECA Initiative, DSD first applied for funding to the Climate Action Secretariat ("CAS"). CAS then forwarded both the application and the program required energy study to the PSECA utility partners (FEU and BC Hydro) for review. The FEU's EEC team performed a technical review and, based on the results was able to conditionally commit funding for several of the upgrades envisioned in the energy study. Prior to receiving any EEC funding DSD must complete the program's process and adhere to its additional terms and conditions, as with all other program participants. The program process requires that all approved upgrades be complete and operational, that proof of purchase be forwarded to EEC, and that EEC staff perform an on-site audit of the installations. Material changes to the systems may result in reduced incentives. Upon satisfactory completion of the program requirements EEC will issue the appropriate incentive.

The amount of EEC funding available to the DSD via their application through the PSECA is not yet finalized. The amounts that DSD references on their web site, including the reference to $800k of EEC funding, are initial estimates only[101]. As such, the final amount of EEC funding will be determined by FEI and released to the School District upon commissioning and on-site audits of the systems. Current analysis of the project application indicates that approximately $100k of EEC funds will be available to DSD due entirely to the use of high efficiency boiler upgrades at some of the sites.

7.4.3 FEU's Internal Controls Ensure Fair Distribution of EEC Incentive Funding

This Section addresses the internal controls in place to ensure that EEC incentives are distributed in accordance with the program principle of universality and the eligibility requirements.

The FEU operate the EEC program as an independent business unit. Only staff from the EEC department have the authority to determine the context in which EEC funds are made available, or to authorize their distribution. This includes:

1. The conception, design and implementation of new EEC programs;

[100] The FEU have also corresponded with the Central Okanagan School District specific to one school about the provision of an EEC incentive under the Commercial Custom Design program, which is described on pages 86 – 89 of the 2010 EEC Annual Report, and included in Appendix G to this Submission. The Companies expect the School District to apply for the incentive.
[101] Please see the response to ESAC IR 2.6.5 in the 2012-2013 RRA proceeding, included in Appendix G.

2. Daily administrative tasks such as the receipt and review of program applications; and
3. The approval and subsequent distribution of EEC incentive funding. Note that the FEU's Energy Solutions or Account Managers staff may deliver incentive cheques to customers in person.

Within the EEC department, the FEU also strive to maintain a separation between the functions of application review and incentive determination versus the ultimate authorization of incentives. All programs have business cases associated with them, and these are approved by the FEU's staff in accordance with the Companies' Expenditure Authority Policy. Further, for programs where large incentives are being paid out, cheque requisitions and Incentive Authorization forms are also completed and approved in accordance with the Companies' Expenditure Authority Policy.

In addition, EEC activities are subject to an annual review by the FEU's Internal Auditors. This review process generates a report detailing the findings of the audit, and making recommendations as required, to further improve EEC program processes and controls. The review done by the FEU's Internal Auditors includes a review of program incentives to ensure that program participants conform to the program's terms and conditions. This report is provided as an appendix to the Companies' EEC Annual Report, filled on an annual basis with the Commission.

No other business group within the company has the authority to execute the above noted functions in connection with EEC incentive funding.

The existing internal controls described above ensure that EEC incentives are distributed appropriately.

7.4.4 Summary: Distribution of EEC Incentives Directed Toward TES Projects is Consistent with Other EEC Programs

Based on the principle of universality that is applied by the FEU, a qualifying customer will receive EEC funding irrespective of asset ownership or their preferred project partner[102]. Ensuring that the programs are available to all qualifying potential participants is part of the FEU's business practice, and ensuring that all applications are compliant with program requirements is an important part of EEC's internal control process. As with all grants or incentives made available in the form of DSM or EEC programs, the customer still has a role to play in accessing and meeting the requirements of such programs to qualify for these funds,

[102] Please see the response to Corix IR 2.5.2 and IR 2.5.7 in the 2012-2013 RRA proceeding, included in Appendix G.

before the funds can be dispensed. Service providers like Corix or ESAC are also free to discuss with any customer EEC funding that may be available to the customer[103].

7.5 COMPARISON TO HOW EEC INCENTIVES ARE DISTRIBUTED BY OTHER UTILITIES

This Section provides an overview of how the FEU's universality principle and process for dispensing EEC incentives compares with the practice in other utilities. The FEU have concluded that the process they follow reflects industry practice. This was confirmed through an expert opinion.

In British Columbia, all energy utilities including the FEU, FortisBC Inc. and BC Hydro, design, deliver and administer their own EEC programs. EEC incentives are available to all customers who qualify under a given program. Elsewhere in Canada, most EEC programs are designed, delivered and administered by the utilities, while others may be administered by a third party administrator. Regardless of who actually administers the programs, the common process for distributing EEC funds tends to be a follows:

1. Customers identify their needs in terms of energy efficiency improvements;
2. Customers communicate with the utilities regarding the availability of incentives;
3. Customers complete qualifying energy efficiency improvements;
4. Customers apply for cash incentives, and forward all required proofs to the utilities;
5. Utilities review the proofs and ensure verify adherence the program's terms and conditions; and
6. On application approval the utilities distribute the incentive funding.

Some programs may require pre-approval of the customer's application, while a non-prescriptive program may require a significant degree of engineering analysis. In some cases the utilities administer the distribution of incentives on the behalf of partners. In such cases, the partners may impose their own requirements on the program process and the distribution of funds.

The FEU's monitor and follow industry standards to ensure that EEC programs and the dispensing of EEC funds are all aligned with BC's energy objectives, government policies, as well as DSM Regulation requirements. Included in Appendix G, is an opinion letter from Jack Habart of Habart & Associates Consulting, which confirms FEU's EEC incentive process reflects industry practice. Mr. Habart is an expert in the area of demand-side management programs.

[103] Please see the response to ESAC IR 2.4.2 in the 2012-2013 RRA proceeding, included in Appendix G.

7.6 PROPOSED GUIDELINES FOR EEC

The fact the Commission has only recently heard EEC-related proceedings, and that aspects of the EEC framework are being addressed in the concurrent 2012-2013 RRA proceedings, reinforces that this Inquiry should be focused on how approved EEC incentives should be dispensed to customers. The information provided in this Section demonstrates that the current approach remains appropriate. It ensures that qualifying customers interested in implementing high-efficiency thermal energy systems - whether self-provided, or by entering into arrangements with the FEU, Corix, an ESAC member or some other third party to provide such a service - have equal access to funding.

The FEU propose the following guidelines:

1. The FEU's existing EEC principle of universal access for all customers is equally suited to EEC that is directed to customers interested in adopting thermal energy.

2. The FEU's existing mechanisms for making funds available are sufficient and appropriate to ensure that funds are made available in an impartial manner to all customers irrespective of whether the customer is going to own and operate the TES facilities, or with whom they chose to partner (the FEU, Corix, ESAC members, or some other party). That process is as follows:

   (a) The FEU establish EEC programs and determines incentive criteria, set in terms and conditions;

   (b) The FEU inform customers about the EEC programs through different communication channels;

   (c) Customer identifies its EEC needs to the FEU;

   (d) Customer completes its EEC improvements/investments;

   (e) Customer applies to the FEU for EEC incentives;

   (f) Applications are reviewed by the FEU to ensure that the program criteria outlined in the terms and conditions of the EEC program are met;

   (g) Incentives are distributed to customers, and not to the third party project partner (whether that is Corix, ESAC member, or the FEU); and

   (h) Customer selects the TES project partner that it sees fit, applying its incentive dollars towards the project cost, if they so choose to use the incentive to reduce their rate for the TES project.

3. Third parties interested in partnering with customers are responsible for finding out what EEC is offered and can encourage their customer-partners to apply to the FEU for incentives.

4. Alternatively, the FEU propose that the Companies develop these guiding principles in the first instance through the established EEC Stakeholder Group, which is an important forum for the FEU to get feedback in all areas of the overall EEC initiative, and submit the guiding principles for Commission approval.

8 SUMMARY OF FEU'S RESPONSES TO ISSUES POSED BY THE COMMISSION AND GUIDELINES FOR NEW INITIATIVES

In this Section of the Filing, the FEU discuss the purpose of guidelines and proposes specific guidelines in response to the Commission's "scope and issues" Appendix A to Order No. G-118-11. The evidence set out in prior sections of the Filing provides the support for the proposed guidelines.

This Section is organized as follows:

- Section 8.1 discusses the purpose of guidelines in the BC regulatory context; and
- Section 8.2 summarizes the FEU's position on the issues identified by the Commission, and sets out our proposed guidelines.

8.1 PURPOSE OF GUIDELINES

It is common practice for tribunals to make and rely on guidelines to assist in their administrative decision-making processes. Guidelines generally assist in ensuring administrative efficiency by providing useful procedural guidance to those who appear before tribunals, and they also provide administrative consistency in decision-making. Guidelines do not and cannot replace a tribunal's enabling legislation. A tribunal that makes a decision based solely on a guideline and without a focus on, and application of, its enabling statute and other governing legislation unlawfully fetters its discretion. As a result, the Commission always retains the discretion to depart from these guidelines in appropriate circumstances. The FEU intend the guidelines proposed in this Filing to be of a nature that identifies considerations and procedural steps, while being phrased in such a manner as to retain for the Commission the necessary flexibility to adapt to circumstances as they arise and avoid the potential for the Commission to fetter its discretion.

8.2 RESPONSES TO ISSUES AND PROPOSED GUIDELINES

In this Section, the FEU set out the Commission's issues, in the sequence that they appear in Order No. G-118-11, and provides a summary response to each. The FEU have also proposed general and specific guidelines.

General Guidelines

The FEU are proposing that the Commission adopt the following general guideline, which recognizes the legal role of guidelines in the regulatory process:

1. These guidelines are intended to provide guidance to stakeholders regarding the Commission's general expectations as the FEU proceed with the New Initiatives.

They do not limit the FEU from bringing forward applications pursuant to the provisions of the *UCA*. The Commission always retains the discretion to determine its own process and depart from these guidelines in appropriate circumstances.

In the recent 2010 Long Term Resource Plan Decision for the FEU, Order No. G-14-11, dated February 1, 2011, page 28, the Commission stated that the New Initiatives are generally in keeping with BC legislation and government policy. The Commission has also provided recent clarification on when an incentive program is a "demand side measure", and how that definition is to be interpreted in light of "British Columbia's energy objectives" and policy. The FEU propose the following general guidelines which reflect such prior Commission determinations on policy:

2. Expenditures and investments in infrastructure to support making Biomethane, NGV fueling service, and thermal energy service available to the FEU customers and potential customers are generally aligned with, and support, British Columbia's energy objectives and Provincial policy, although the extent to which each initiative do so will differ in each case, as will the Commission's assessment of the weight given to the policy considerations relative to other considerations.

3. EEC expenditures that are directed at providing incentives to customers to improve energy efficiency, educate customers about energy efficiency, and supporting the necessary administration to deliver the initiatives, are "demand side measures" and are aligned with British Columbia's energy objectives and provincial policy.

The above guidelines only recognize past determinations of the Commission, and will not predetermine whether or not particular expenditures for New Initiatives proposed in the future are in the public interest. Rather, the effect of adopting these policy-related guidelines or principles going forward is to acknowledge that the determination of the public interest in particular instances will normally turn on other considerations (e.g. customer benefits and impact), rather than on whether or not they support provincial policy objectives. Adopting these principles as an outcome of this Inquiry avoids the need for the FEU to re-file extensive general policy evidence in each future proceeding where the FEU is requesting public interest approvals relating to New Initiatives. The outcome will be a more focussed public interest examination of proposed projects and expenditures and ultimately, more efficient Commission processes.

More specific guidelines relating to the issues posed by the Commission in Order No. G-118-11 are set out below.

Issue 1 – Evaluating AES and Other New Initiatives

Issues 1(a) and 1(b)

The FEU believe that issues 1(a) and 1(b) are closely related. They are therefore discussed together below.

Issue 1(a) asks Inquiry participants to comment on the following issue:

> *When evaluating AES and other new initiatives, what principles or guidelines should be followed by the BCUC to protect the public interest including:*
>
> > *the interests of utility ratepayers;*
> > *the impact on the broader public including potential competitors;*
> > *the furthering of British Columbia's energy objectives; and*
> > *the rights of the utility shareholder?*

Issue 1(b) asks Inquiry participants to comment on the following issue:

> *What process should the BCUC utilize and how comprehensive should its analysis be before it allows the utility to undertake AES or other innovative technologies as part of its regulated business?*

The FEU have interpreted the scope of "AES or other new initiatives" referenced in Issue 1(a) and "AES and innovative technologies" in Issue 1(b) to include Biomethane Service, NGV Service (both of which are part of the natural gas class of service), and TES (which is its own class of service). Considerations relevant to how EEC funding is dispensed are addressed in the context of Issue 1(c). There are different considerations in the context of each of the three services, and thus the FEU have provided separate responses to Issues 1(a) and (b) for each of Biomethane Service, NGV Service, and TES.

Issues 1(a) and 1(b): Biomethane

The Biomethane offering is discussed in Section 4. In that Section, the FEU discuss why the Commission should maintain the regulatory review of the Biomethane Service that is to take place at the end of 2012, as contemplated in Order No. G-194-10. That review is slated to examine aspects of both the Biomethane rate offering and the supply-side of the initiative. However, the FEU believe that this Inquiry is the appropriate forum to establish guidelines on the following matters:

(a) The considerations relevant to determining when the FEU will own and operate biogas upgrading equipment; and

(b) The appropriate process for the Commission to review biogas upgrading projects advanced by the FEU.

Stakeholders will benefit from certainty on this issue before the FEU undertake the comprehensive examination of the initiative at the end of 2012.

The FEU propose the following Biomethane supply-side guidelines:

1. It is important for the FEU to own and operate the *interconnection* facilities (i.e. measuring, monitoring, and odourizing) to ensure the quality and safety of the biomethane being injected into the distribution system.

2. Facilities for the *collection* of raw biogas (e.g. digester) are unregulated. Where the FEU are to become owners and operators of collective facilities, appropriate mechanisms would have to be put in place to reflect the non-regulated nature of the business. As the FEU are not currently anticipating owning and operating biogas collection facilities, no further guidelines on this matter are required at this time.

3. The FEU should consider proposals from project partners[104] to own and operate the upgrading facilities, and assess whether those partners can demonstrate financial and technical capability to do so.

   (a) The FEU's assessment of financial capability should involve consideration of whether the partner has financial resources to purchase and operate the equipment, and manage contingencies such as equipment failures or system improvements that may require additional capital.

   (b) The FEU's assessment of technical capability should involve consideration of whether the project partner has a strong technical knowledge of gas and gas related equipment.

   The FEU should also give consideration as to whether the project partner proposing to own and operate the upgrading facilities can provide the upgrading service for the same or lower cost than would be the case were the FEU to own or operate the upgrading facilities.

4. The Commission recognizes the benefit of a streamlined regulatory process when it comes to Biomethane supply projects, and also recognizes that energy supply contracts are typically accepted by the Commission without process and supplemental evidence. Therefore, the following procedural guidelines are appropriate:

   (a) The CPCN threshold established for the FEU (currently $5 million) applies to biomethane upgrading facilities to be owned and operated by the FEU. Projects

[104] This might be the owner of the collection facilities, or a third party. It is anticipated that if a third party were to become involved, it would likely be as a project partner with the owner of the collection equipment such that the true owner and operator would be the owner of the collection equipment, rather than purchasing raw biogas, upgrading it, and reselling it to FEU at a mark-up. However, the FEU would give consideration to proposals under either scenario.

that are estimated to cost in excess of the threshold shall be reviewed through the ordinary CPCN process and in accordance with the Commission's CPCN guidelines.

(b) The FEU is at liberty to apply for an expenditure schedule for upgrading facilities costs below the CPCN threshold, or otherwise have the costs considered in the normal course as part of a future revenue requirements process.

(c) When filing contracts for upgraded biomethane (i.e. the project partner, and not the FEU, owns and operates the equipment for upgrading the biogas to biomethane), without the FEU seeking an expenditure schedule or a CPCN it will be sufficient for the FEU to file only the supply contract under section 71 of the *UCA* with information confirming that the supply is required. In such circumstances, the Commission expects that its consideration can normally occur without further process.

(d) When filing supply contracts for raw biogas (i.e. where the FEU will own and operate the equipment for upgrading the biogas to Biomethane) under section 71 of the *UCA*, in addition to any other information confirming that the supply is required, the FEU will provide the following information to the Commission in summary form:

(i) Confirmation that the owner of the collection facilities is not interested in owning upgrading facilities; or

(ii) If the project partner remains interested in owning and operating the upgrading facilities, but the FEU is instead proposing to own and operate the upgrading facilities itself based on its assessment of the items identified in 3 above, the FEU's assessment of why (with reference to the items identified in 3 above) the FEU ownership is preferable.

Issues 1(a) and 1(b): NGV

As outlined in Section 5, the Commission's recent decision in the FEI's NGV Application substantially addressed Issues 1(a) and 1(b). In the NGV Decision, the Commission addressed the interests of ratepayers, the impact on the broader public, the fact that the NGV Service offering furthers British Columbia's energy objectives, and the rights of the FEU's shareholder. In particular, the Commission generally accepted that the service confers benefits on FEU's customers, the customer taking the service, and the public generally (the focus of the discussion in the NGV Decision on benefits was with the *quantum* of these benefits). The FEU will be filing revised GT&Cs for CNG/LNG Service that reflect the cost and revenue allocation principles articulated in the NGV Decision.

The FEU submit that, in light of the recent NGV Decision, there is no need for the Commission to articulate further guidelines and principles regarding the NGV offering itself. However, as contemplated in the Application and the Decision, going forward the FEU will need to file individual "take-or-pay" contracts with the Commission for rate approvals. Future regulatory review of the tariff supplements can be streamlined to account for the Commission's acceptance that the NGV offering is, in principle, beneficial, subject to the FEU filing amended GT&Cs. The FEU believe that the following are appropriate procedural guidelines in this context:

1. The CPCN threshold established for the FEU (currently $5 million) applies to NGV facilities, including pumping facilities for individual customers, any needed system additions or upgrades that are necessary as a result of additional NGV load, or liquified natural gas supply resources or facilities involved with loading and transporting these products. Projects that are estimated to cost in excess of the threshold shall be reviewed through the ordinary CPCN process and in accordance with the Commission's CPCN guidelines.

2. The FEU are at liberty to apply for an expenditure schedule for the types of facilities outlined above when costs fall below the CPCN threshold, or otherwise choose to have the costs considered in the normal course as part of a future revenue requirement process.

2. The Commission has recognized in the NGV Decision that investments in fueling infrastructure necessary to facilitate CNG/LNG Service share common benefits, which include:

    (a) lower delivery rates for existing customers through added load, all else equal;

    (b) economic benefits for fleet owners;

    (c) advancement of British Columbia's energy objectives; and

    (d) a fair return on invested capital for the shareholder.

    Only the extent of these benefits will vary from project to project. Therefore, in the event that the FEU apply for acceptance of an expenditure schedule in respect of fueling station infrastructure, the evidence required by the Commission will generally be limited to the CNG/LNG Service agreement and a brief statement quantifying the following: the delivery rate impact, GHG emissions savings and general economic benefits captured by British Columbia's energy objectives; an estimation of fuel cost savings flowing to the fleet owner and any potential for those cost savings to be passed on to others (e.g. municipality contracting with the fleet owner for hauling service); and the shareholder's return on invested capital.

3. Regardless of whether the FEU apply for acceptance of an expenditure schedule for an investment in CNG/LNG fueling facilities, the Commission's approval of the associated CNG/LNG Service agreement will generally be persuasive evidence at the time cost

recovery is sought that the FEU's decision to invest in the supporting assets (as opposed to how effectively the project was executed) was prudent. This is because the rate design specified in the NGV Decision secures cost recovery from the NGV customers.

4. In circumstances where the potential NGV customer has selected FEI as its project partner for providing CNG/LNG Service, evidence of the existence of another third party alternative provider of a similar CNG/LNG service would only be given weight in the public interest assessment of the FEU's CNG/LNG fueling station project if the third party provider files evidence to establish that:

   (a) The customer (notwithstanding its contract with the FEU) wants to partner with the third party, and not FEU; or

   (b) The interest of the CNG/LNG Service customer in accessing service from the FEU as its preferred partner at a rate based on the FEU's cost of service:

      (i) is outweighed by the corporate interests of a non-regulated provider in providing that service despite the preference of the CNG/LNG Service customer to work with the FEU; and/or

      (ii) is outweighed by a long-term benefit to customers generally that flows from overriding the specific customer's preference to work with the FEU.

5. The Commission recognized in the NGV Decision that its directed modifications to the proposed CNG/LNG Service rate design could affect the rate of take-up of the service, and was satisfied with that trade-off to reduce risk to other natural gas customers. Nevertheless, the FEU are encouraged to apply for modifications to the approved CNG/LNG Service rate design based on new evidence that the approved rate design is presenting a significant impediment to the adoption of CNG/LNG Service, such that the interests of ratepayers in reduced risk is outweighed by lost opportunities to build load.

6. The Commission's NGV Decision addressed rate design in the context of CNG/LNG Service, which is focussed on recovery of costs associated with the fueling station. The FEU's investment in new or expanded upstream facilities, such as LNG production and storage, may give rise to different rate design considerations that would have to be addressed by the FEU.

Issues 1(a) and 1(b): TES

The Commission has previously approved a rate schedule for TES in the FEI 2010-2011 RRA NSA (section 12A of the FEI GT&Cs, Alternative Energy Extensions). The FEU believe that guidelines can be built on that framework, and will assist in the efficient regulatory review of Thermal Energy Services projects.

With respect to the Commission's Issue 1(a), the FEU propose the following guidelines for the Commission's public interest evaluation of TES projects:

Interests of Ratepayers

1. When the Commission evaluates a TES project, a consideration of the interests of ratepayers involves a consideration of:

    (a) customers of the natural gas class of service;

    (b) the potential TES customer(s) who will receive service from the TES project; and

    (c) other TES customers within the TES class of service that share with the TES project the common costs of the TES class of service.

2. With respect to the interests of natural gas customers:

    (a) The interests of natural gas customers are protected through the application of appropriate cost allocation methodologies, and through the segregation of the two classes of service (i.e. natural gas and TES) as required by the *UCA*, with TES costs of service being recovered from TES customers.

    (b) Natural gas customers benefit from an allocation of indirect/overhead costs to TES, which would otherwise be recovered in natural gas rates.

    (c) Natural gas customers benefit from additional gas throughput associated with a TES project that incorporates natural gas as part of the energy solution. Considerations relating to the load-factor associated with such natural gas load, and how that drives capital investments in natural gas facilities, should be addressed through FEI's Phase "B" Rate Design Application that will occur in 2012 and other future rate design applications over time.

3. With respect to the interests of the specific customer that wishes to adopt thermal energy service:

    (a) The TES customer is making a choice:

        (i) to have a thermal energy system in place of natural gas service, electricity, or some other fuel alternative; and

        (ii) to work with FEI as its project partner.

        The TES customer has an interest in the Commission giving effect to that choice.

(b) TES customers of a specific TES project should pay a rate that recovers the direct project-specific costs over the life of the project and its portion of the allocated overhead and business development/sales costs.

(c) TES customer of a specific TES project should not pay for costs associated with the natural gas class of service, except to the extent those costs result from natural gas being incorporated into the project. These costs would be derived under existing natural gas rate schedules.

4. With respect to the interests of the customers of the TES class of service generally:

(a) TES customers generally should contribute through their rates to the recovery of the balance in the Thermal Energy Services Deferral Account, which reflects common costs, overhead and sales/marketing costs, business development costs of providing TES service.

(b) TES customers should not pay for costs associated with the natural gas class of service, except to the extent that they are also natural gas customers.

5. When properly applied by FEI, rates for TES service based on FEI's GT&Cs, Section 12A, and other rate constructs established in the 2010-2011 RRA proceeding:

(a) adequately protect the interests of customers of FEU's natural gas class of service;

(b) generate cost of service based rates for TES; and

(c) allow for a TES project rate to recover a portion of costs from the Thermal Energy Services Deferral Account.

Interests of Competitors

6. Potential TES customers will have a range of considerations, desires, and preferences in selecting a TES provider (such as the FEI, Corix or ESAC members). As a non-regulated entity, the TES customer should be left to determine the nature of, or manage, the selection process it undertakes.

7. The Commission's interest in competition is related to concerns about whether the competitive market place best serves customers through, for instance, competitive pricing. The Commission has no general mandate to oversee competition, increase competition or to favour one market participant over another.

8. The FEU are entitled to use their own corporate strengths to compete for TES customers to the extent lawfully permitted by competition and consumer protection legislation[105].

9. In circumstances where the potential TES customer has selected FEI as its project partner, evidence of the existence of another third party alternative provider of TES would only be given weight in the public interest assessment of the FEU's TES project if the third party provider files evidence to establish that the interest of the TES customer in accessing service from FEI as its preferred partner at regulated rates is outweighed by a long-term benefit to customers generally that flows from overriding the specific customer's preference.

Interests of Broader Public (generally) and furthering British Columbia's Energy Objectives

10. The FEU collectively serve at least half of British Columbians, and there is thus considerable overlap between the interests of customers and the interests of British Columbians generally.

11. British Columbia's energy objectives, which must be considered in the context of public interest assessments under sections of the *UCA* applicable to TES, are an expression of the broader public interest. The public interest is also informed by other expressions of government energy policy.

12. A TES system that reduces GHG emissions and/or provides economic benefits is in the interest of British Columbians generally.

13. The adoption of a TES, as opposed to electricity, for heating load can reduce cost pressure on the electric system due to avoidance of high cost supply and potentially capacity-driven infrastructure. Since most British Columbians require electricity service regardless of whether they use electricity for heating purposes, any potential savings of this nature is relevant to the broader public interest.

The Rights of the Utility Shareholder

14. Under the *UCA*, the shareholder's interest is in earning a fair return on, and return of, its invested capital. To that end, as recognized in the Commission's past cost of capital decisions, TES rates must provide the FEU with an opportunity to earn a fair return on, and return of, its invested capital in TES projects.

[105] The FEU's position is that Commission-approved cost of service rates for TES that are consistent with the *Act*, by definition, cannot be predatory.

15. The shareholder has an interest in finding ways to combat declining natural gas use rates, which represents a challenge to its ability to recover its capital invested in natural gas assets over time. TES that incorporate a natural gas component assists in this regard to the extent that the customer might otherwise adopt a thermal energy solution that does not incorporate natural gas.

Guidelines for TES Regulatory Process

The following proposed process guidelines necessarily presume that the provision of TES by FEI is a regulated public utility service for the purposes of the *Act*; otherwise, the Commission would not oversee these projects. That issue is addressed later in this Section in respect of Issue 2(a).

In terms of the process for the review of regulated TES projects, the FEU believes that the appropriate regulatory process should balance the interest of customers in maintaining adequate Commission oversight of such projects with the interests of all stakeholders in having an efficient and cost-effective review process. On this basis, the FEU believe that an appropriate model for the review of such projects would consist of the following elements.

1. As contemplated in the NSA for the 2010-2011 RRA, FEI will continue to offer thermal energy services within the service areas of FEVI and FEW, instead of FEVI and FEW.

2. The CPCN threshold established for the FEU (currently $5 million) applies to TES facilities. Projects that are estimated to cost in excess of the threshold shall be reviewed through the ordinary CPCN process.

3. The FEU is at liberty to apply for an expenditure schedule for TES facilities costs below the CPCN threshold.

4. In order to maximize regulatory efficiency while maintaining appropriate oversight commensurate with the nature of the investment, it is appropriate to adopt different processes depending on the size of the investment contemplated. For projects that are estimated to cost between $1M and the CPCN threshold (currently $5M), irrespective of whether the FEU are seeking an expenditure schedule or just approval of a rate, the FEU will be expected to file together with a tariff supplement (i.e. the customer's service agreement) based on Section 12A of the GT&Cs:

   (a) A brief project description, including:
      (i) An overview of the overall project;
      (ii) The estimated in-service date and project schedule;
      (iii) System components;
      (iv) Load analysis;
      (v) Project risks; and
      (vi) The rate paid by the customer and the inputs that determine the rate.

(b) The estimated project costs;

(c) The following information to help assess the appropriateness of the proposed thermal energy charge and contractual rate design:

(i) an estimate of the number of customers to be served by the thermal energy system;

(A) the consumption estimates for each customer (or class of customers);
(B) projections for when the customers will be connected to the proposed system;

(ii) the full labour, material, and other costs necessary to serve the new customers less any contributions in aid of construction by the Customers or third parties, grants, tax credits, or non-financial factors offsetting the full costs that are deemed to be acceptable by the Commission;

(iii) the appropriate allocation of FEI's overheads associated with the construction of the alternative energy extension;

(iv) depreciation expense related to the capital equipment associated with the alternative energy extension; and

(v) the incremental operating and maintenance expenses necessary to serve the customers.

5. For projects that are estimated to cost under $1M, the FEU will file a tariff supplement based on Section 12A of the GT&Cs (i.e. the customer's service agreement), supported by a brief statement setting out:

(i) an estimate of the number of customers to be served by the thermal energy system;

(A) the consumption estimates for each customer (or class of customers);
(B) projections for when the customers will be connected to the proposed system;

(ii) the full labour, material, and other costs necessary to serve the new customers less any contributions in aid of construction by the customer or third parties, grants, tax credits, or non-financial factors offsetting the full costs that are deemed to be acceptable by the Commission;

(iii) the appropriate allocation of FortisBC Energy's overheads associated with the construction of the alternative energy extension;

(iv) depreciation expense related to the capital equipment associated with the alternative energy extension; and

(v) the incremental operating and maintenance expenses necessary to serve the customers.

6. Upon receiving the materials described in items 4 and 5, the Commission will consider whether any process is required. If the Commission determines that a process is required, the hearing will normally proceed by way of a written hearing, consisting of one round of information requests and final submissions.

7. The scope any proceeding for projects below the CPCN threshold will normally be limited to the following:

(a) the items that are to be included in the project description;

(b) the amounts set out in a filed cost estimate or expenditure schedule, and the basis of those amounts;

(c) the rate or rates applied for and the basis of those rates.

For clarity, it is the Commission’s intention to avoid unnecessarily revisiting larger policy issues and matters related to cost allocation as between the natural gas class of service and the TES class of service, which have been addressed in this Inquiry.

8. The Commission’s approval of an expenditure schedule filed in respect of a thermal energy system can be cited by the FEU as evidence that the FEU’s decision to invest in the supporting assets (as opposed to how effectively the project was executed) was prudent.

Issue 1(c): EEC

Issue 1(c) asks Inquiry participants to comment on the following issue:

To what extent and under what conditions could EEC or other funding be made available to support AES and other new initiatives?

The FEU respectfully suggest the following guidelines:

1. The FEU’s existing EEC principle of universal access for all customers is equally suited to EEC that is directed to customers interested in adopting thermal energy.

2. The FEU's existing mechanisms for making funds available are sufficient and appropriate to ensure that funds are made available in an impartial manner to all customers irrespective of whether the customer is going to own and operate the TES facilities, or with whom they chose to partner (the FEU, Corix, ESAC members, or some other party). That process is as follows:

   (a) The FEU establish EEC programs and determines incentive criteria, set in terms and conditions;

   (b) The FEU inform customers about the EEC programs through different communication channels;

   (c) Customer identifies its EEC needs to the FEU;

   (d) Customer completes its EEC improvements/investments;

   (e) Customer applies to the FEU for EEC incentives;

   (f) Applications are reviewed by the FEU to ensure that the program criteria outlined in the terms and conditions of the EEC program are met;

   (g) Incentives are distributed to customers, and not to the third party project partner (whether that is Corix, ESAC member, or the FEU); and

   (h) Customer selects the TES project partner that it sees fit, applying its incentive dollars towards the project cost, if they so choose to use the incentive to reduce their rate for the TES project

3. Third parties interested in partnering with customers are responsible for finding out what EEC is offered and can encourage their customer-partners to apply to the FEU for incentives.

4. Alternatively, the FEU propose that the Companies develop these guiding principles in the first instance through the established EEC Stakeholder Group, which is an important forum for the FEU to get feedback in all areas of the overall EEC initiative, and submit the guiding principles for Commission approval.

Issue 2 – Regulated versus Non-regulated Activities

Issue 2(a)

Issue 2(a) asks Inquiry participants to comment on the following issue:

> *What are the principles that should be applied to determine whether an AES or other new initiatives activity can or should be pursued as a regulated business?*

The *Utilities Commission Act* dictates what services are regulated through the definition of "public utility" in section 1 of the *UCA*. There is no discretion embedded in the definition of "public utility"; either it applies to an entity or it does not. The Commission is not empowered to decide, as a matter of regulatory policy, that certain entities which otherwise meet the definition are not subject to the *UCA* (subject to limited exceptions that require the involvement of the minister or the Lieutenant Governor in Council)[106]. Consequently, there is no need to develop principles that should be applied to determine whether an AES or any other new initiative can or should be pursued as a regulated business. A legal analysis of how the definition of "public utility" applies in the context of the Biomethane Service, NGV Service and TES is presented in Section 3 and the specific chapters relating to the initiatives.

Issue 2(b)

Issue 2(b) asks Inquiry participants to comment on the following issue:

> *Where an AES activity or other new initiative has been undertaken by a regulated utility to allow it to be proven or established and after that it is determined that it should be spun out as an unregulated activity, what cost/benefits should accrue to the ratepayer and/or the utility shareholder? What principles or guidelines should the Commission [sic.] to follow in assessing an application to spin out a regulated activity to a non-regulated entity?*

Sections 4, 5, and 6 of this Submission explain that the FEU currently intends to hold Biomethane upgrading facilities and CNG/LNG Service facilities as natural gas assets, and to hold TES assets within a class of service of FEI. The FEU have no intention of "spinning out" these assets. In any event, the transfer of regulated assets requires Commission approval. As a result, the FEU believe that the only necessary guideline applicable to this scenario is one that reflects the explicit provisions of the *UCA*:

1. The sale of regulated TES assets at the request of the FEU requires Commission approval, thus providing the Commission and stakeholders with an opportunity to consider any proposal on a case by case basis.

As a point of clarification, with the exception of the CNG/LNG Service facilities[107], if these assets were to be sold or transferred to another entity, they would not become unregulated. The

[106] There are only two provisions of the *Act* that allow for the exemption of persons from regulation under the provisions of the *Act*: Section 22 provides that the minister, by regulation, may exempt certain persons from section 71 and the provisions of part 3 of the *Act*; and section 88 provides that with the advance approval of the Lieutenant Governor in Council, the Commission may except a person, equipment or facilities from the application of all or any of the provisions of the *Act*.

[107] CNG/LNG Service facilities would become unregulated if they were owned by an entity that was not otherwise a public utility.

Commission does not have the jurisdiction to order that an activity that is, by definition, regulated under the *Act* (see Issue 2(a)) be "spun out as an unregulated activity". Either an activity carried out by a person meets the definition of "public utility" or it does not. If an activity meets the definition, then the person carrying out that activity is a public utility and subject to Part 3 of the *UCA*; otherwise, that person is not subject to the *UCA*.

In the event that the Commission is asking about guidelines for when it can *direct* the sale of the assets relating to a previously approved pilot, the FEU submit that the Commission does not have that jurisdiction under the *UCA*. The Commission does, however, have the jurisdiction to cease a pilot, consider the prudence of the expenditures incurred to that point in support of the pilot, and to exclude imprudently incurred expenditures from rate base. At that point, assets deemed to have been imprudently acquired would become unregulated assets held by the FEU, and could be disposed of by the FEU at its option at a gain or loss as the case may be. As such, the applicable guideline in this scenario is one that identifies that cost recovery and rate basing is assessed according to the established prudence test. The prudence test is outlined under Issue 3(a) below. The FEU believe, however, that the decision to install the assets required for a pilot will generally be prudent where it was done based on a prior public interest approval issued by the Commission.

Issue 2(c)

Issue 2(c) asks Inquiry participants to comment on the following issue:

> *What are the practices in other jurisdictions with respect to AES and other new initiatives (including the application of EEC) that are allowed to be undertaken as part of the regulated business and what is the degree of oversight by the regulator in approving and monitoring these activities?*

The FEU have provided in this Filing information regarding practices in other jurisdictions for the New Initiatives. However, as described in further detail in Section 3, Applicable Legal Principles, the scope of regulated activity turns on the provisions of the *UCA*, irrespective of what occurs in other jurisdictions. As such, the only guidelines proposed by the FEU is:

1. The scope of regulated activity turns on the provisions of the *UCA*, irrespective of what occurs in other jurisdictions.
2.

Issue 2(d)

Issue 2(d) asks Inquiry participants to comment on the following issue:

> *Under what conditions should a regulated utility be allowed to share market sensitive information it has obtained through its regulated business activities with non-regulated businesses (a) that are related businesses or (b) unrelated businesses?*

The use of information is addressed in Section 6 of this Filing, in the context of TES projects. The proposed guidelines reflect the FEU's consideration of the applicable law or past decisions:

1. Subject to any particular legislative or contractual obligations, or a specific request by a customer that information be shared, the FEU should not provide unrelated businesses with personal or commercial information about the customer.

2. With respect to related companies within the Fortis Group, the FEU should apply the Commission-approved code of conduct that governs the sharing of information between the FEI and non-regulated businesses approved by L-64-1997.

3. With respect to the sharing of customer information within the FEU between regulated classes of service, subject to applicable privacy legislation it is generally appropriate for utility staff with access to information and resources in the possession of the utility to be made available for the benefit of thermal energy services customers.

Issue 3 – Evaluation of Approved Regulated TES and Other New Initiatives

Issue 3(a)

Issue 3(a) asks Inquiry participants to comment on the following issue:

> *When ratepayers are paying for AES and other new initiatives what standards should the BCUC apply to determine whether the activity is being carried out in the most cost-effective manner?*

The Commission has the ability at the time it is assessing an application for a CPCN, for instance, to express concerns about particular options, make directions, or impose conditions. The Commission has previously articulated what is meant by cost-effectiveness[108].

In assessing cost recovery, however, the FEU believe that the well established prudence standard is appropriate for the review of expenditures related to New Initiatives, just as it is for all other public utility expenditures[109]. Accordingly, in response to this issue the FEU propose the following guideline, which reflects the law regarding the review of past public utility expenditures:

1. A decision of the FEU regarding an expenditure on New Initiatives is presumed to have been made prudently unless those challenging the decision demonstrate reasonable grounds to question the prudence of that decision. At the second stage of the inquiry,

[108] See VITR Decision, July 7, 2006, pp. 12-15, referring to VIGP Decision, September 8, 2003, regarding the meaning of "cost-effectiveness" for the purposes of considering a CPCN application.

[109] The Commission has confirmed that the two part prudence test from *Enbridge Gas Distribution Inc. v. Ontario (Energy Board)*, [2006] O.J. No. 1355, is the proper test for reviewing the cost consequences of past management decisions: *BC Hydro F2009 and F2010 Revenue Requirements*, Decision, March 13, 2009, p. 38.

reached only if the presumption of prudence is overcome, the FEU must show that its business decision was reasonable under the circumstances that were known to, or ought to have been known to, the FEU at the time it made the decision.

Issue 3(b)

Issue 3(b) asks Inquiry participants to comment on the following issue:

What principles or guidelines should be applied to ensure that where feasible competitive forces can be utilized to maximize the efficiency and effectiveness of AES activities and other new initiatives?

The FEU understand that this issue is focused on efficiency and effectiveness, which are benefits from a customer perspective[110]. The proposed guidelines on customer considerations are addressed above in the context of Issue 1(a).

Issue 3(c)

Issue 3(c) asks Inquiry participants to comment on the following issue:

What guidelines should utilities follow in making EEC incentive funds available for addressing issues such as (i) who can access the funds, and (ii) transparency of funding programs?

See response to Issue 1(c).

Issue 3(d)

Issue 3(d) asks Inquiry participants to comment on the following issue:

What criteria should be used to assess whether an AES or new initiative activity has been successful in meeting the initial objectives set out for the activity? If the activity has not been fully meeting the goals set out in the initial application, what criteria should be used to determine when the program should be terminated? What portion of the risk of program failure should rest with the ratepayer?

[110] There is both provincial and federal legislation in place that address issues of unfair competitive practices, and the Commission must respect the intention of the provincial legislature and of parliament to have matters of unfair competitive practices addressed through those pieces of legislation. With respect to fair competition, the FEU have proposed guidelines for TES and NGV regarding the Commission's limited role with respect to competition.

The FEU believe that it is not appropriate to fix criteria in advance for assessing when to end programs, but offer the following general comments. In most cases, the same criteria used in assessing an application made by the FEU for approval of an expenditure related to a New Initiative should also be used to evaluate program success. That is, the applications will state the reasons why the program is in the public interest and should be approved, and those reasons (typically ratepayer benefits, benefits to the broader public, advance BC Energy objectives) will be the appropriate criteria for such an assessment. Generally speaking, when the Commission believes that a new project's benefits no longer outweigh the program's costs, or will not advance the benefits outlined in the initial application for the program under which the project is advanced, then the Commission may wish to consider terminating the program on the basis that it is no longer in the public interest. The Commission should take care in allowing sufficient time to pass to allow programs to gain traction before engaging in this analysis.

In a situation where a program is terminated, the existing contracts already entered into under the program should generally be allowed to run their course, and the service provided under those contracts should continue. The customers taking the service may be relying on the service continuing, and there may be impediments to the customer taking an alternative service.

To the extent that any programs costs have not been recovered when all of the contracts under a program have come to an end, any remaining costs, and the question of who should bear them, should be considered using the well-established prudence test (described above).

APPENDIX A

Business Environment

1. 2008 Long Term Resource Plan Excerpts
2. 2010 Long Term Resource Plan Excerpts
3. 2010-2011 TGI RRA Application Excerpt
4. Energy Environment in BC

2 THE PLANNING ENVIROMENT

The planning environment sets the context within which energy demand will grow and evolve over the next 20 years. Currently, this environment is undergoing a great deal of change, creating uncertainty in how the energy future in B.C. will unfold over the next several years or even months. Driven by rising energy costs, increasing demand from population growth and social and political reaction to climate change concerns; new policies and legislation have been and continue to be introduced with far reaching implications for energy production, consumption and infrastructure. This chapter provides an overview of the planning environment in which this plan is set. Appendix B examines regional energy planning issues in more detail.

The key messages documented and supported in this Chapter are:

- Since both natural gas and electricity produced and used in B.C. are bought and sold across political boundaries within the region, energy planning and emission issues should be considered within a regional context.
- In political jurisdictions and utility service areas throughout the PNW, natural gas is widely viewed as the environmental choice for fueling a majority of required new electricity generating facilities, since in most jurisdictions new large hydro projects are not permitted due to their impact on the environment. Other renewable resources are limited, leaving natural gas as the best alternative to accompany what renewable resources can be developed.
- Since using natural gas for space heating and other appliances in the home is more efficient than using natural gas to generate electricity (the marginal resource in the PNW) for use in the same applications, direct use of natural gas is the preferred choice for these uses over electricity. Where alternative energy systems such as heat pumps make sense, natural gas remains the preferred back-up fuel.
- Demand for natural gas throughout the region is thus expected to continue growing into the next decade and beyond, led by growth in the residential and electricity generation sectors.
- Utilities and other major buyers of natural gas in the region are seeking cost effective means to increase the diversity of their supply options in order to improve supply reliability and reduce cost exposure from single source supply as demand grows.
- In B.C., where renewable electricity alternatives are more widely available than elsewhere in the region, direct use of natural gas for home heating and appliances is still the right fuel choice over electricity because:
    - B.C. currently imports up to 15% of the electricity needed to meet domestic load requirements[2] and that electricity is primarily generated from lower efficiency coal and natural gas power plants, resulting in higher Greenhouse Gas ("GHG") and pollution emissions than would result if that self-sufficiency shortfall was met through the direct use of natural gas.

---

[2] http://www.bchydro.com/policies/index/index3196.html

- o Even when B.C. becomes electricity self sufficient sometime in the future, as set out in the 2007 Energy Plan, electricity produced using green and renewable electricity generated in B.C. can/could be exported to displace coal and natural gas fired generation elsewhere in the region, again reducing GHG and pollution emissions.
- o With population in B.C. expected to grow by roughly one million people over the next 20 years[3], direct use of natural gas in homes and businesses, along with aggressive energy efficiency, conservation and alternative technology programs, will be an important part of helping to meet the expected tremendous growth in energy demand while reducing GHG emissions throughout the region.
- o The biggest opportunity for GHG and pollution emission improvements in B.C. lies within the transportation sector where 39%[4] of B.C.'s GHG emissions are produced. Natural gas can play a significant role in reducing GHG emissions and other pollutants from this sector and help the province reach its GHG reduction targets.
- o Even when the cost of carbon emissions has been applied through carbon taxes and other mechanisms, direct use of natural gas is expected to remain an economically competitive energy choice for direct use in homes and businesses.
- o All of these natural gas solutions will help B.C. to meet the objectives of the 2007 Energy Plan.

In summary, natural gas in direct use applications is best suited for space and water heating. Electricity, regardless of the fuel used to generate it, should be used for applications where no other fuel substitute is available since these uses alone are creating growth in demand. Further, with B.C. currently being electricity short, natural gas in direct use applications will help to meet growing demand for energy, whereas electricity relied on to meet growing space and water heating loads will make the province's self sufficiency and renewable electricity targets more difficult and expensive to reach.

2.1 Energy Trends and Policies in the Pacific Northwest Region

In this Resource Plan, the term region or regional refers generally to the Pacific Northwest ("PNW"). PNW refers most commonly to the 4 northwestern states (Washington, Oregon, Idaho and Montana) and B.C, also referred to hereafter as the "Region". In some cases, discussion about the Region is expanded to include Alberta and/or Alaska since energy produced in each jurisdiction is traded, transported and consumed throughout the PNW. California is also a Pacific Coast jurisdiction whose actions have many implications for B.C. California has a large population and is a large consumer of energy resources, both from within it borders and elsewhere, including the PNW. It is also a leader in energy efficiency and alternative technologies, and initiatives to address climate change.

3 http://www.bcstats.gov.bc.ca/DATA/pop/pop/project/bctab1.asp

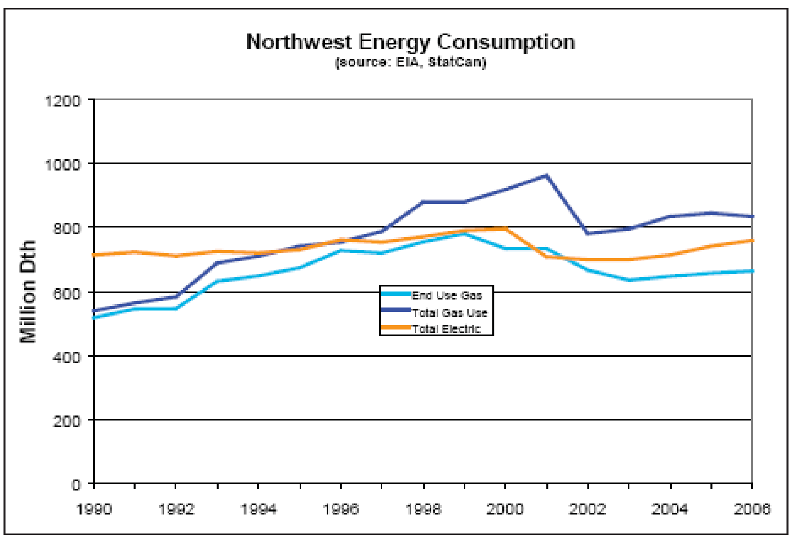
4 NRCan Comprehensive Energy Use Database for BC

The demands for natural gas and electricity are interlinked through each one being a substitute energy source for the other, and through the use of natural gas as a major source of fuel for existing and planned new generation in the Region. Since both of these energy types are traded across political boundaries and B.C. trades these resources physically within the Region, energy planning in B.C. must consider the regional implications and impacts of the decisions being made. Terasen Gas' participation in the regional energy market means gas procurement activities are conducted in a competitive environment where access to and the cost of resources is affected by regional supply and demand balances.

2.1.1 Demand Trends – Natural Gas and Electricity

In the Pacific Northwest, consumption of natural gas surpasses that of electricity (see Figure 2-1). With continuing population growth expected, demand for both of these energy sources will continue growing. This diagram also indicates that to meet growing electricity demand, use of natural gas as a generation fuel in the region has been increasing since the early 1990s. This trend is evident throughout the period, with the exception being a one-time permanent reduction in industrial demand from the shutting down of the PNW aluminum industry (affecting both electricity and natural gas demand) associated with the Western energy crisis of 2001 – 2002. It is clear that regional demand for both of these energy types is closely linked.

Figure 2-1 Total Gas and Electricity Consumption in the PNW (B.C., Id, OR & WA)

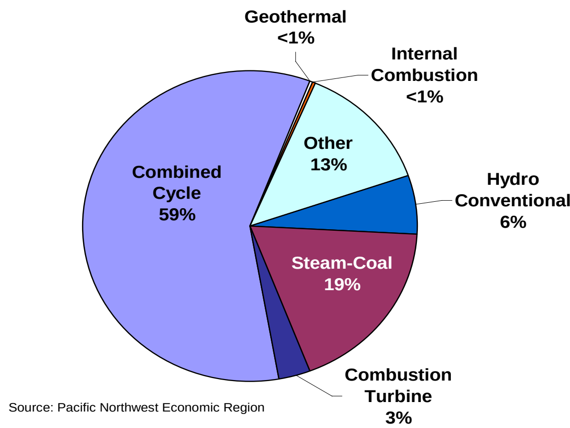


(End use gas is that gas which used for space heating and appliances in homes and businesses.

The difference between total gas use and end use gas is therefore electricity generation fuel.)

Data provided by the Pacific Northwest Economic Region ("PNWER") shows that on a regional basis this trend of increasing gas use for electricity generation is expected to continue. Figure 2-2 indicates that the majority of new generation additions in the region are expected to be fuelled by natural gas. A review of Resource Plans for electric utilities in the region shows that, with the exception of BC Hydro, these utilities plan to rely increasingly on natural gas-fired generation to meet growing electricity demand and future resource requirements. The market is responding by developing new supply alternatives that will service the Region and help to keep natural gas prices competitive. These new supply alternatives are discussed in more detail in Chapter 6.

Figure 2-2 Summary of Electricity Generation Facility Additions 2005 – 2014

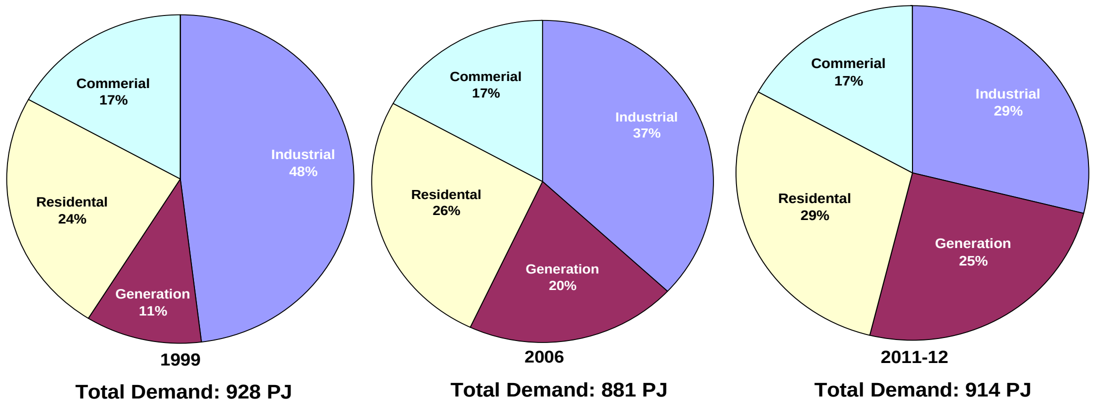


Recent legislation in most jurisdictions in the Region calls for renewable generation resources to make up a greater proportion of utility resource portfolios. In most areas of the Region, however, the renewable resources available are limited to primarily intermittent resources such as wind, small hydro and solar projects that are unable on their own to meet either the expected growth in demand or reliability requirements. For this reason, conventional sources of non-renewable resources[5] are required to both meet the growth in electricity demand and to firm up the intermittent renewable resources that are being added to the electricity grid. Since there are essentially no large hydro projects available except for in B.C., and new coal-fired generation is not permitted or is accompanied by high development risks as a result of expected carbon and pollution emission regulations, most utilities seeking new generation resources are turning to natural gas as a key component of future resource additions.

The NWGA reports the resulting changes in the composition of regional demand shown in Figure 2-3. The progression shown in these charts indicates that the proportions of generation fuel and residential demand are growing while industrial gas demand has declined. The right hand chart in Figure 2-3 shows that, with overall demand for natural gas having recovered from the energy crisis of 2001 – 2002 (see also Figure 2-1), growth in these two sectors is expected to continue driving the incremental demand for natural gas into at least the next decade.

[5] Within the Pacific Northwest, only BC considers large Hydro projects as renewable resources.

Figure 2-3 the Changing Make-up of Natural Gas Demand in the Pacific Northwest



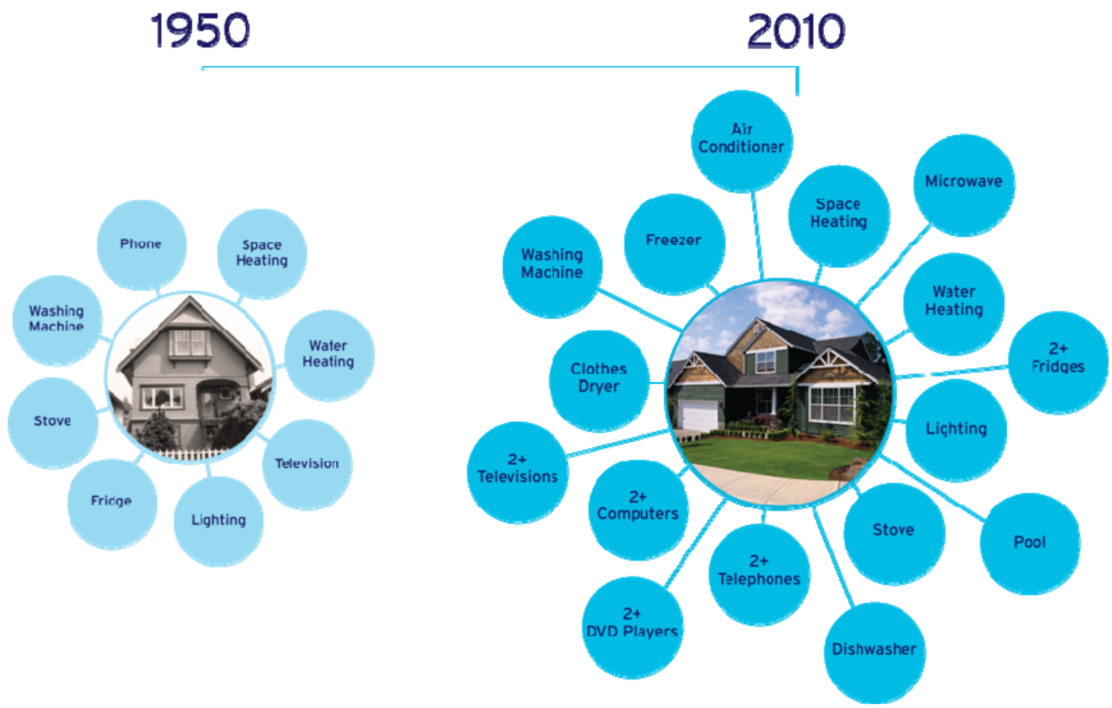
Source: EIA, StatsCan, NWGA

Each year the NWGA prepares a Regional Outlook Study (see Appendix C) which, among other things, reviews these trends. The 2007 Outlook Study noted that the combination of increasing residential and generation demand is causing peak demand to grow more quickly than base load demand, driving the need for new peaking or storage resources. The study also noted, however, that few large base load resources (pipelines) have been added in the Region in recent years and that these resources need to be encouraged in order to access growing production and improve supply diversity. These trends are discussed further in Chapter 6.

2.1.2 Residential Fuel Choice in PNW

Natural gas and electricity are the two most common energy sources for home heating in the PNW. Compared to electricity, natural gas has fewer direct use applications in the home. Where electricity can be used to run lights, electronics and other electric equipment in addition to space and water heating applications, natural gas can only be used for space heating, hot water and appliances. Figure 2-4 shows how, in addition to the growth in population and new homes that require electricity, the number and type of uses for electricity within each home has also grown, making the burden on B.C.'s electricity resources increase much faster. It is important, therefore, that the right fuel be used for its most efficient application wherever practical and cost effective.

Figure 2-4 The Evolution of Residential Demand for Energy



Since natural gas is the marginal source of electricity generation in the PNW, the relative efficiency of these two energy types is an important factor in choosing a home heating fuel, both in terms of energy efficiency and GHG emissions. Since gas fired generating facilities typically operate at between 30 and 55%[6] efficiency, the case is easily made in most areas for direct use of natural gas in the home at 80 to 95% efficiency[7] for new natural gas appliances. In service areas outside of B.C., the choice for direct use of natural gas in homes where available is made easier by the relatively lower cost of natural gas as a heating fuel as shown in Figure 2-5. These principles are being adopted by more and more utilities[8] in the PNW and continue to be studied by regional agencies[9].

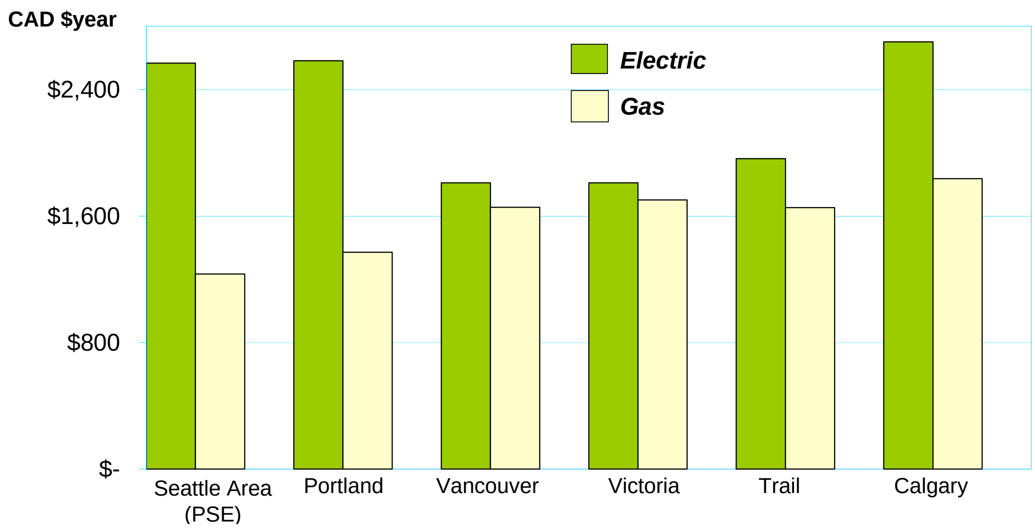
[6] 50-55% is the expected efficiency of a typical new combined cycle, gas fired generating facility. Simple cycle or older combined cycle facilities and coal plants operate at lower efficiencies and have higher GHG emissions – source: Canadian Power Industry Course, 2007. www.powercourses.ca

[7] These are industry standards for mid and high efficiency furnaces respectively.

[8] Avista Energy, a combined electric and gas utility, has been conducting fuel switching to direct use of natural gas since 1991 and Puget Sound Energy is now developing similar programming.

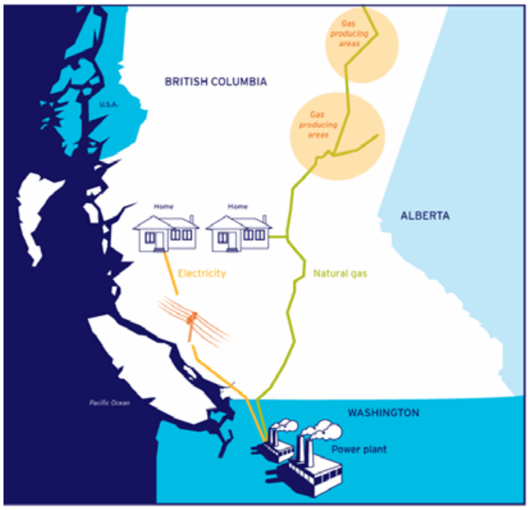
[9] Both the NWGA and NWPCC are undertaking studies related to the potential for direct use to support regional energy objectives.

Figure 2-5 Cost of Natural Gas vs. Electricity for Home Heating in the PNW



ASSUMPTIONS:
Annual Bill - 110 GJ/year
1 USD - 1.03 CAD Bank of Canada USD Conversion Rate
1 GJ = 9.4782 Therms and 277.78 kWh
The electric rates are 90% efficiency adjusted
Rates include all applicable riders
Other utilities' rates are estimates only

Direct Use

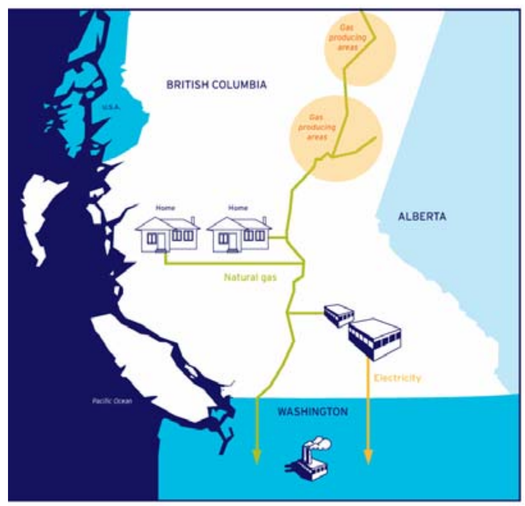


Direct use of natural gas for space and water heating in homes and businesses in B.C. will help to meet the electricity self sufficiency targets of the B.C. Energy Plan and will reduce carbon emissions throughout the Region. The growing amount of electricity that B.C. imports is largely generated from natural gas and coal fired generation plants located elsewhere in the PNW. Using natural gas directly at the end use is much more efficient than using it to generate electricity for use in space and water heating.

←

When B.C. reaches its self-sufficiency, surplus and green targets for electricity by 2016 as set out in the Energy Plan, the surplus green electricity will be available for export to neighbouring jurisdictions to replace natural gas and coal fired generation there. Utilities in other parts of the Region are continuing to pursue the potential for programs to replace electric radiant and water heating with natural gas.

→



Focus on Issues

2.2 Energy Trends & Policies in British Columbia

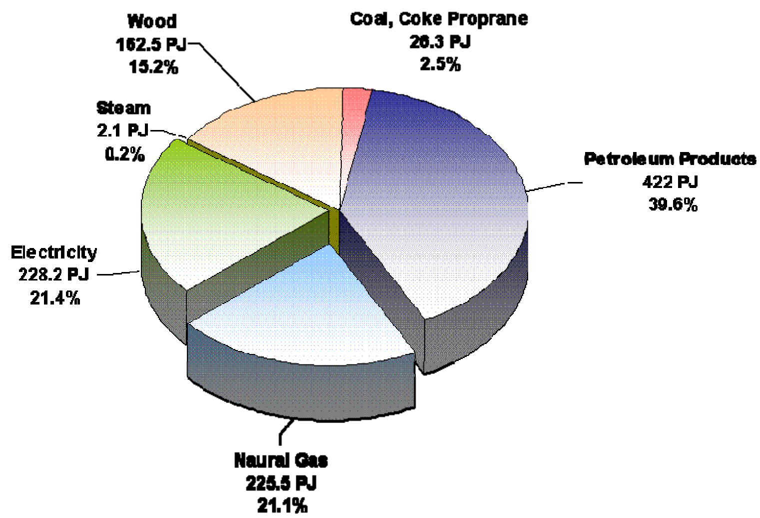
2.2.1 Provincial Demand for Energy

Across all sectors and energy types, 1,066 petajoules ("PJ ")[10] of energy were used in 2004 in B.C. Figure 2-6 shows the distribution of fuel consumption in B.C. across energy types. Petroleum products, consisting largely of transportation fuels, represent the largest slice of this

[10] NRCan Comprehensive Energy Use Database

chart. Consumption of natural gas and electricity in the province is approximately equal, each at 21% of annual energy consumed. While B.C. is a net exporter of natural gas (70 - 80% of the natural gas produced here is exported[11]), the province imports approximately up to 15% of BC Hydro's electricity[12] and 70+% of its petroleum[13].

Figure 2-6 Annual Energy Consumption in B.C. across Energy Types



Source: NRCan Comprehensive Energy Use Database, BC Stats

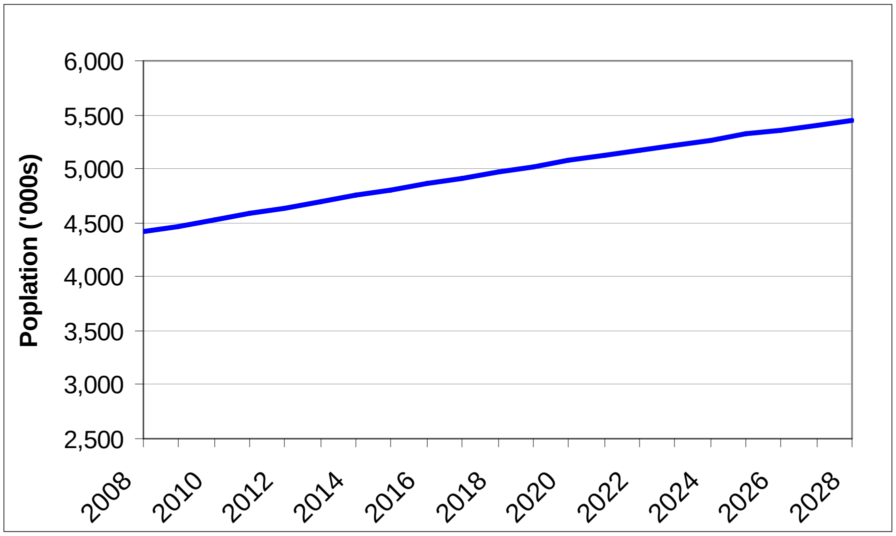
The population in B.C. grows by approximately half a million people every decade (see Figure 2-7). Even with more aggressive conservation and energy efficiency efforts by all utilities and end users, energy consumption will grow to meet the needs of this expected population increase even where use per customer rates are falling. These statistics have important implications for energy costs, carbon emissions and fuel choice in B.C. and the PNW.

[11] BC Ministry of Energy, Mines & Petroleum Resources, Oil & Gas Division

[12] http://www.bchydro.com/policies/index/index3196.html

[13] BC Ministry of Energy, Mines & Petroleum Resources, Oil & Gas Division

Figure 2-7 B.C. Population Growth



Source: B.C. Stats

In summary, the size of overall energy demand depicted by the pie chart in Figure 2-6 will continue to grow. Intensification of EEC programs play an important role in helping to meet incremental demand for energy, but cannot be expected to reverse demand growth. The size and nature of each portion of the pie chart will be determined by a combination of energy costs (capital and operational), government policies and legislation, and education programs that will allow the public to make informed energy use decisions.

2.2.2 Provincial Energy Policy and Regulation

Energy policies and regulation in B.C. have been changing quickly in recent years as a result of both the need to meet increasing energy demand and Provincial climate change response initiatives. A summary review of the various new Provincial legislation and policies below provides regulatory context within which Terasen Gas must set objectives and plan resource development activities.

The 2007 BC Energy Plan – A Vision for Clean Energy Leadership

This Resource Plan has been prepared with consideration for all of the policies in the BC Energy Plan. Key policies in the plan with implications for Terasen Gas Include:

Environmental Leadership -

- Net zero GHG emissions from all new electricity generation and from heritage thermal generation by 2016.
- Clean and renewable generation to account for 90% of B.C.'s total electricity generation resources.
- Promote energy efficiency and alternative energy.
- Bring clean power to communities.
- Address GHG's from transportation.

Energy Conservation and Efficiency -

- Acquire 50% of BC Hydro's incremental electricity needs by 2020 through conservation.
- Implement energy efficient building standards.

Energy Security -

- Maintain B.C.'s competitive electricity rate advantage
- Achieve electricity self sufficiency by 2016.
- Make small power part of the solution.
- A decision on the future of Burrard Thermal.

Innovation -

- Establish the Innovative Clean Energy Fund.
- Implement the B.C. Bioenergy Strategy to take advantage of renewable resources.

Develop B.C.'s Oil and Gas Resources -

- Be among the most competitive oil and gas jurisdictions.
- Be a leader in responsible oil and gas development.

Utilities Commission Amendment Act, 2008 ("UCA Act")

Introduced as Bill No. 15, this legislation received Royal Assent, becoming law, on May 1st, 2008. As described in Section 1, the UCA Act revises a number of sections of the *Utilities Commission Act* with respect to resource planning, including the requirements for utilities to prepare resource and energy efficiency and conservation plans as described in Chapter 1. Conservation planning is discussed in Chapter 4.

The UCA Act puts into law many of the policies of the 2007 B.C. Energy Plan, containing the requirement for BC Hydro to achieve electricity self-sufficiency by 2016, install smart metering and implement the standing offer program. The province wide target for 90% of electricity generation from clean and renewable resources is also formalized in this Act. While these policies may not appear on the surface to impact Terasen Gas, they have implications for the competitive environment in which the utilities operate and provide some direction for Terasen Gas to undertake initiatives that help meet these goals and policies.

The UCA Act also adds a new definition of "government's energy objectives" to section 1 of the *Utilities Commission Act.* These objectives have implications for utility resource planning efforts, encouraging public utilities to:

(a) reduce greenhouse gas emissions;

(b) take demand-side measures;

(c) produce, generate and acquire electricity from clean or renewable sources;

(d) develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility;

(e) use innovative energy technologies;

(i) that facilitate electricity self-sufficiency or the fulfillment of their long-term transmission requirements, or

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

(f) take prescribed actions in support of any other goals prescribed by regulation.

The Greenhouse Gas Reductions Targets Act (“The Targets Act”)

The Targets Act was brought into force January 1, 2008. The Targets Act enshrines in law the provincial government’s commitment to becoming carbon neutral, and sets province wide targets for greenhouse gas reductions of 33% from the 2007 level by 2020, and 80% from the 2007 level by 2050. Targets for 2012 and 2016 are to be set by regulation before the end of 2008. While the Targets Act sets targets for making all levels of government and government facilities carbon neutral, it does not specify how the province should achieve these goals.

Bill 37 - Carbon Tax Act

The Carbon Tax Act was introduced as creating a revenue-neutral carbon tax, and requiring the Minister of Finance to return carbon tax revenues to taxpayers through tax cuts. The tax is intended to apply effective July 1, 2008 to the retail purchase or use in BC of the majority of fossil fuels, including gasoline, diesel fuel, natural gas, home heating fuel, propane and coal. The initial tax rate will be based on $10 per tonne of carbon dioxide-equivalent emissions released from burning the fuel, and will increase by $5 per tonne over the following four years reaching $30 per tonne as of July 1, 2012. This Act will add $0.50 per gigajoule (“GJ”) to the cost of natural gas in the first year, rising to $1.50 / GJ in the third year of implementation.

Other legislation / regulation that is under development or has recently been passed by the BC Government and which has implications for energy planning are:

- Bill 16 - 2008 Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act
- Bill 18 - Greenhouse Gas Reduction (Cap and Trade) Act
- Bill 27 - Green Communities Act
- Bill 31 - 2008 Greenhouse Gas Reduction (Emissions Standards) Act
- Bill 39 - 2008 Greenhouse Gas Reduction (Vehicle Emissions Standards) Act
- The BC Green Building Code

The initiatives and actions described in this Resource Plan are aimed at addressing either the regulations themselves or the intent of this legislation to reduce carbon emissions and improve energy efficiency.

The Innovative Clean Energy Fund

Although the Innovative Clean Energy Fund itself is not legislation, it has been developed by the B.C. Government as part of its commitment to the 2007 BC Energy Plan. The fund, built up through B.C. utility customer contributions as a nominal tax on their energy bills, is intended for the development and implementation of new, alternative energy solutions in the Province. The Terasen Gas alternative energy initiatives discussed in Chapter 7 of this Resource Plan address the intent of the Province in setting up this plan and through application to the fund can benefit the Provinces utility customers through the development of clean and alternative energy resources.

2.2.3 Competitiveness of Energy Alternatives

2.2.3.1 Natural Gas and Propane Commodity Prices

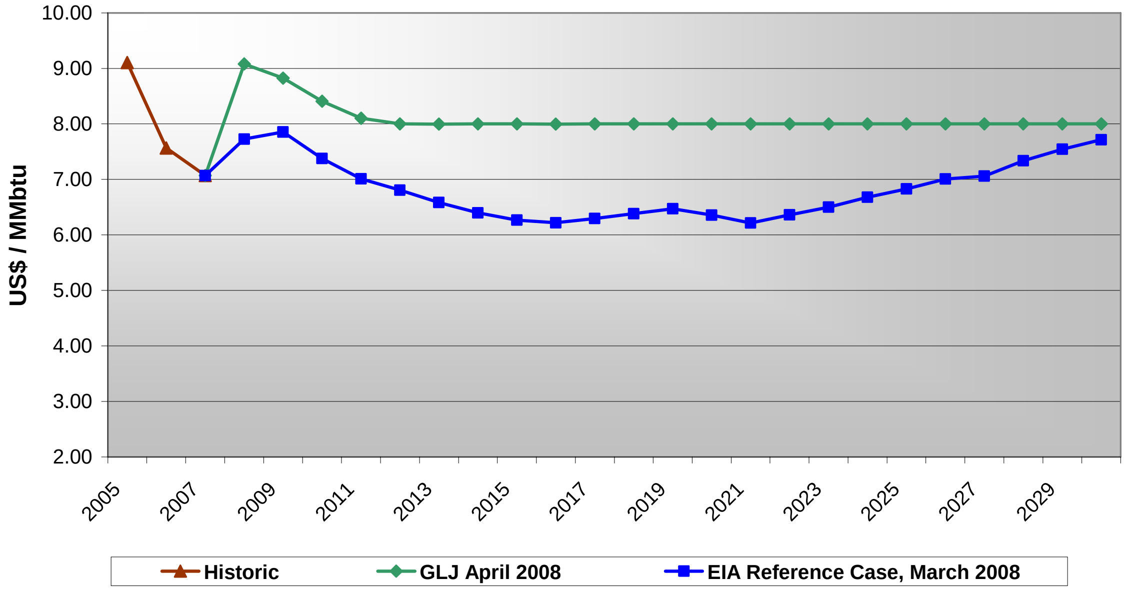
Trends in natural gas and electricity prices send signals to consumers making buying decisions on energy system equipment and fuel choices. Since these are the two primary energy choices for consumers in BC, expectations by consumers of future price increases in the supply of either energy type relative to the other can impact customer additions and load forecasts. This section presents a discussion of natural gas price forecasts prepared by independent sources, as well as a discussion on recent trends and price pressures in electricity and comments on Energy Pricing made by the BC Progress Board in their review of energy opportunities and imperatives in BC. Information reviewed by TGI in preparing this Resource Plan points toward the continued competitiveness of natural gas prices as upward pressures on electric rates continue.

Natural Gas Price Forecasts

Terasen Gas generally utilizes price forecasts generated by other industry experts when analyzing likely future gas consumption for its own customers. GLJ Petroleum Consultants Ltd. ("GLJ") is a private petroleum industry consultancy serving clients who require independent advice relating to the petroleum industry, including the preparation of natural gas and oil price forecasts on a quarterly basis. GLJ prepares commodity price and market forecasts after a comprehensive review of information available to the reported quarter. Information sources include numerous government agencies, industry publications, Canadian oil refiners and natural gas marketers. GLJ's forecasts reflect tracking recent trends in oil and gas supply, demand and transportation issues as well as other trends in the natural gas industry and the cost of competing fuels.

The U.S. Energy Information Service (“EIA”) also prepares a range of gas price forecasts against which the GLJ forecast can be compared for reasonableness. The EIA uses the last 30 years of data, including normal weather and storage inventories to generate the price forecasts. EIA’s 2008 Annual Energy Outlook forecast was released in December 2007, but was subsequently revised to include the impact of the “Energy Independence and Security Act of 2007”. Only the reference case forecast was re-released. The reference case reflects reduced expectations for economic growth and now includes provisions for energy efficiency standards on home heating equipment and other appliances, along with other measures to lower carbon emission intensity. Figure 2-8 presents the GLJ and EIA reference case natural gas demand price forecasts.

Figure 2-8 Third Party Long-range Gas Price Forecasts – Henry Hub



Both forecasts have incorporated the expectation of short-term price increases resulting from current market conditions and production levels. Moving into the mid-term, these forecasts also account for the market expectation of lowering prices as production increases and transmission infrastructure expands to improve access to supplies. Over the longer term, the EIA forecasts a gradual increase in prices, while GLJ keep prices flat in constant dollars.

Short Term Price Considerations

Market prices for natural gas are currently higher than most price forecasters have predicted. The market expectation of short range price increases for natural gas followed by declining, but seasonal pricing is shown in Figure 2-9, which includes forward gas prices against oil based fuel prices. Further discussion on commodity price competitiveness is contained in Appendix D.

Figure 2-9 Historic and Settled Future Commodity Prices – Oil and Natural Gas

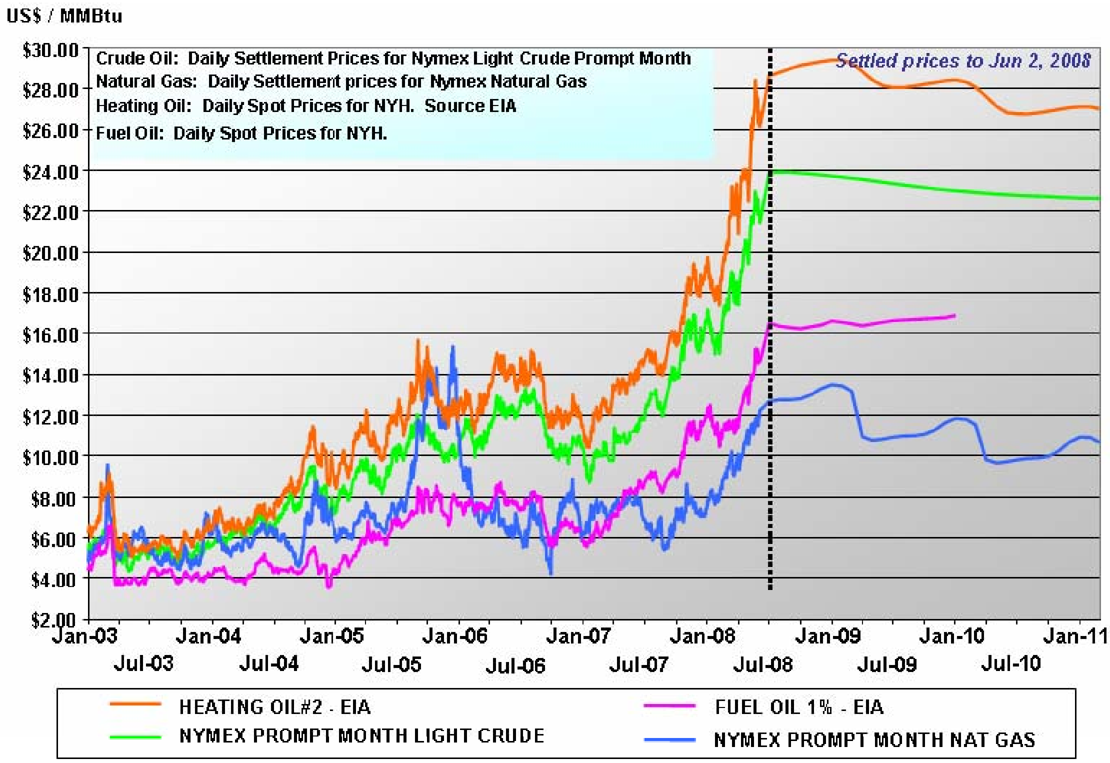


Figure 2-9 also shows that, while oil prices have increased dramatically through 2007 -2008, the separation between oil and gas prices has become larger. This separation may be in part due to the difference in the dynamics of global oil markets versus more regional natural gas markets. The volatility of gas prices is also apparent in this graph along with the trend that spikes in gas prices tend to be short lived.

Propane Prices versus Natural Gas

Some Terasen Gas customers, primarily in Whistler and Revelstoke, are served by Propane Distribution systems. In Whistler, the decision to convert TGW's propane system to natural gas and extend a gas pipeline from Squamish was based in part on the divergence between gas and the more expensive propane commodity prices. Figure 2-10 shows that this divergence has continued. Figure 2-11 shows that TGW's cost for propane has continued to separate from TGI's cost for natural gas. Although this trend will likely be somewhat cyclical, propane prices tend to follow the higher of oil or natural gas prices. Figure 2-10 suggests these trends will continue and oil is currently priced much higher than natural gas. As a result, Whistler customers will benefit from lower commodity rates once the system conversion from propane to natural gas is completed in 2009.

Figure 2-10 Historic Natural Gas Prices versus Propane and Crude Oil

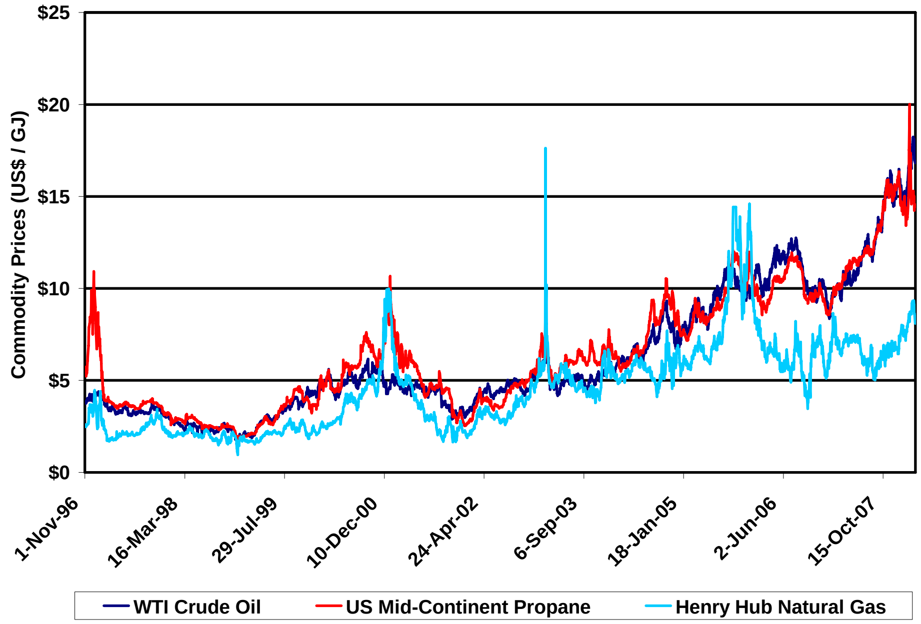
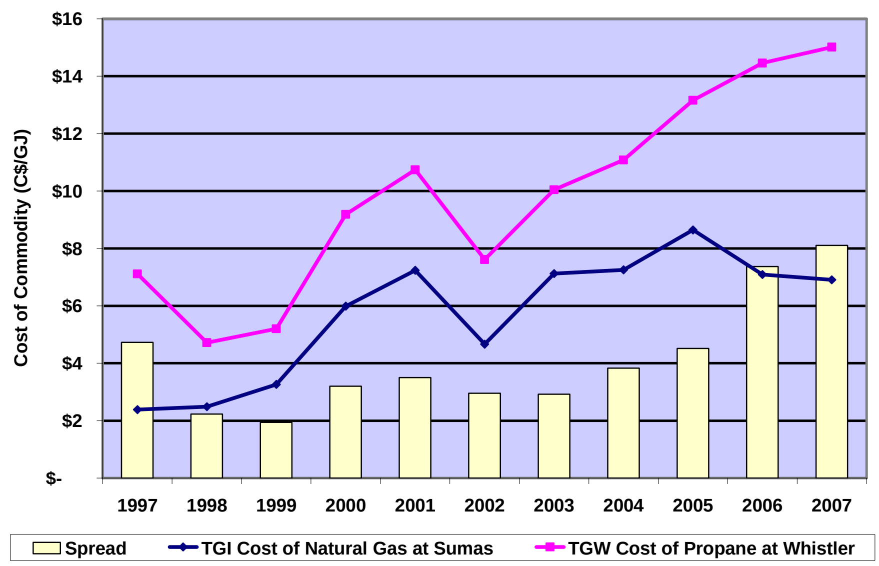


Figure 2-11 Natural Gas versus Propane Commodity Costs for TGW



2.2.3.2 Rate Competitiveness for Heating Energy Choice in BC

Equally important to fuel choice for Terasen Gas customers is the relative annual cost of various heating choice alternatives. While the primary alternatives still remain gas and electricity in B.C., both air and ground source heat pumps are gaining the attention of consumers. A comparison between traditional electric heating systems and natural gas is a relatively straight forward comparison of consumption levels and rates; however, both the physical and economic effectiveness of heat pumps are area and site specific. In addition to comparing traditional fuel choices, Terasen Gas has examined the benefits and risks of installing both ground and air source heat pump technology. A more detailed description of these comparisons can also be found in Appendix D.

Natural Gas and Electric Comparison

Figure 2-12 provides a historical and projected comparison of natural gas bills with the comparable electricity bills. The natural gas bills are based on 110 GJ/year and an assumption of 90% efficiency, while the electricity bills assume 100% efficiency. Going forward the electricity bills include BC Hydro's applied-for F2009 and F2010 revenue requirements increases as well as a proposed inclining block rate being implemented to promote energy conservation in keeping with Provincial energy objectives. Natural gas rates and bills are held constant based on the forward commodity prices discussed above displaying a moderate downwards trend. However, the B.C. carbon tax on natural gas has been added according to the phase-in schedule prescribed by the Province.

Figure 2-12 Residential Natural Gas and Electricity Bill Comparison

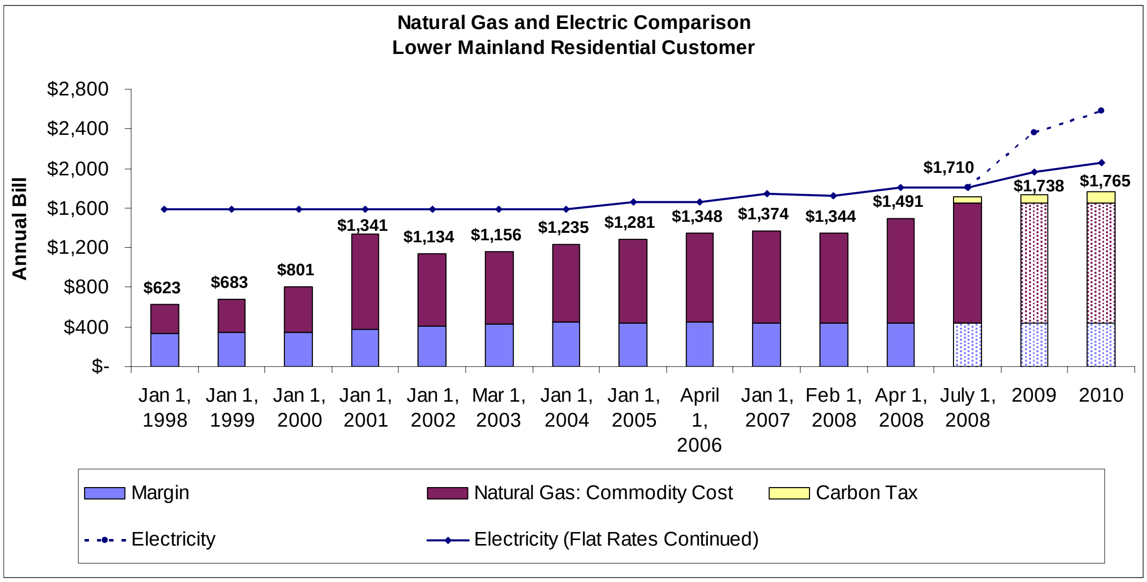


Figure 2-12 demonstrates that while the historical natural gas cost advantage has experienced erosion, natural gas has maintained a favourable competitive position relative to electricity. In the future, the competitive position of natural gas is likely to improve even with the new carbon tax included, particularly if the residential inclining block rate structure is approved and implemented[14].

[14] The residential inclining block rate structure is also referred to as BC Hydro's Residential Inclining Block ("RIB") Rate Application.

Natural Gas Compared to Heat Pumps

In comparing natural gas to air source and ground source heat pumps ("ASHP"s and "GSHP"s, respectively) a few general comments need to be made. Alternative energy systems tend to be characterized by higher upfront capital costs and lower ongoing operating costs (resulting from lower energy consumption) relative to natural gas-based systems. Alternative energy systems also tend to have higher maintenance costs, which erodes some of the benefits of lower operating costs. There are also more unique aspects with these energy systems from one installation to the next than with natural gas-based systems. The cost and configuration of GSHPs, for example, depends on local surface geology and soil conditions. The effectiveness of ASHPs depends on local climate – their efficiency falls off in colder conditions. Further, it is not generally cost effective to size ASHPs and GSHPs to meet the entire peak heating load of a dwelling. A backup system consisting typically of electric baseboard heaters or a natural gas furnace is needed to meet peak heating requirements in the winter, thus increasing the overall capital cost to implement a heat pump system.

Appendix D reviews example comparisons between heat pump technology and high efficiency gas systems from the view point the consumer. The following general observations are made:

- Initial capital cost differences between natural gas systems and ASHPs or GSHPs continue to be significant. Without incentives or other external sources of support, the higher upfront capital costs are likely to continue to be an obstacle to the penetration of ASHPs and GSHPs in the space heating market.
- Annual operating and maintenance ("O&M") costs of ASHPs and GSHPs are currently lower than those for natural gas systems; however, the annual cost advantage is not large enough to provide pay back of the upfront capital cost difference over a reasonable timeframe. With expected trends in electricity rates the annual O&M cost advantage currently enjoyed by ASHPs and GSHPs relative to natural gas installations may be diminished.
- ASHPs and GSHPs operate at higher efficiencies than natural gas systems and on this basis would be expected to provide benefits in achieving the energy efficiency and environmental objectives in the province. However, increased adoption of these technologies may increase the challenge of achieving electricity self-sufficiency in B.C., potentially resulting in increased reliance on imported power until self sufficiency is achieved. This will delay achievement of the desired environmental benefits. Increased adoption of ASHPs and GSHPs will also further impact the cost pressures being faced by electric utilities by increasing annual and peak electricity demand.

2.3 Implications for Planning and Action at Terasen Gas

A growing population is driving a growing demand for all types of fuels. Provincial policies are directing utilities to plan for more intensive energy efficiency and conservation programming, however, these programs will not reverse the need for more supply. Natural gas will continue to play an important role in the energy solutions and economy of the province and the region.

This Resource Plan has been developed with consideration that direct use of natural gas for residential heating is by and large preferred over electrical heating systems both now and once B.C. reaches electricity self sufficiency some time in the future. This assumption is based on the principle that the wisest and most efficient use of energy alternatives must consider the region in which energy resources are traded and carbon emissions are created, rather than be limited to jurisdictional boundaries.

Gas supplies and infrastructure are also needed to meet growing demand for gas fired generation elsewhere in the PNW. Both residential direct use and electricity generation create weather related demand. As these demand sources grow, peak demand will continue to increase relative to base load demand. Since few base load resources have been added in the Region in recent years, however, the number of proposals for base load or pipeline resources are also increasing. Terasen Gas needs to examine alternative regional resource proposals and support those that ensure its own customers continue to have access to reliable and cost effective supply to meet both peak and base load demand.

Terasen Gas has examined the competitive position of natural gas compared to a range of energy system alternatives, particularly for home space and water heating. Upward pressure is expected on costs for all energy types and systems. Generally, natural gas is expected to remain both an economically competitive alternative and a lifestyle choice for residential use. Where alternative energy systems such as heat pumps do appear to make sense for consumers, Terasen Gas expects natural gas continue to play an important role in many of these applications.

It remains possible; however, that natural gas will become a less intensively consumed if alternative energy systems become more available and economical. It is also possible that natural gas will become more intensively used than today if the principle of direct use to help reduce electricity load in BC and elsewhere in the Region becomes more widely adopted by governments, utilities and society as a whole. Terasen Gas needs to examine these alternative futures as well.

In summary, Terasen Gas must continue to develop resources and initiatives that ensure natural gas remains competitive, is used in the wisest and most efficient manner and is part of new clean energy and efficiency initiatives. All of these elements are included in this Resource Plan.

APPENDIX B

Terasen Gas Discussion Paper
Regional Energy Policy Issues

TABLE OF CONTENTS

DISCUSSION PAPER - REGIONAL POLICY ISSUES

1 INTRODUCTION

Global climate change, energy policy and environmental concerns attributable to human energy use have become topics of daily public discussion in recent years in many different forums. Recently in British Columbia the provincial government has made a number of strong public commitments in the areas of energy policy and climate change. These commitments have been supported with the issuance of policy statements and in many cases with the passing of legislation. Further policy statements, legislation and regulation are anticipated from all levels of government in Canada and the U.S.

The effects of human-induced greenhouse gas ("GHG") emissions on climate change and the mitigation of these effects are the central drivers of these energy and environmental policies. The use and combustion of fossil fuels (coal, oil, gasoline, natural gas, etc.) is a leading source of GHG emissions caused by human activity. Land use changes (e.g. from forest to agricultural use or rural to urban) also contribute to atmospheric GHG levels by reducing/changing carbon absorption capabilities of the land. Certain agricultural activities and practices such as the raising of animals for meat, dairy and poultry products are also measurable contributors to atmospheric GHG levels.

Natural gas is a major source of energy in BC accounting for approximately 21% of end use energy consumption.[1] This is approximately the same share of the end use energy market in the province as electricity. Natural gas production and consumption accounts for approximately 34% of the provincial greenhouse gas emissions[2]. As a fossil fuel the future role of natural gas in the BC energy mix comes into question in light of the public policy pronouncements on energy and climate change. Although the combustion of natural gas produces the lowest GHG emissions of any fossil fuel and negligible levels of other pollutants, such as nitrogen oxides, sulfur oxides and particulates[3], compared to the combustion of other fossil fuels and biomass, natural gas is often grouped together with other fossil fuels without any recognition of these attributes. This paper will support the premise that natural gas is part of the solution and that continued use of natural gas,

[1] BC NRCan End Use Database, BC Stats

[2] The BC Energy Plan: A Vision for Clean Energy Leadership, February 2007, page 20

[3] GHG and other emissions for fossil fuels are available from the NRCan GHGenius modeling software at: http://www.oee.nrcan.gc.ca/transportation/tools/greenhouse-gas-info.cfm?attr=16

particularly in direct end-use applications, will assist in the achievement of public policy goals. This paper will also identify the differences on these issues from one jurisdiction to the next in the Pacific Northwest and show how British Columbia's contribution in the region can be improved with natural gas playing a key role.

2 PLANNING ENVIRONMENT – REGIONAL RESOURCE PLANNING OUTLOOK

The key components of the utility resource planning process include the forecast demand and the available resources to meet projected load. Terasen Gas Inc.'s ("TGI") participation in the Pacific North West ("PNW") regional energy market means gas procurement activities are conducted in a competitive environment where access to and the cost of gas supply, storage and transportation are driven by regional supply and demand balances. This section provides an overview of emerging trends in natural gas supply and demand in the region.

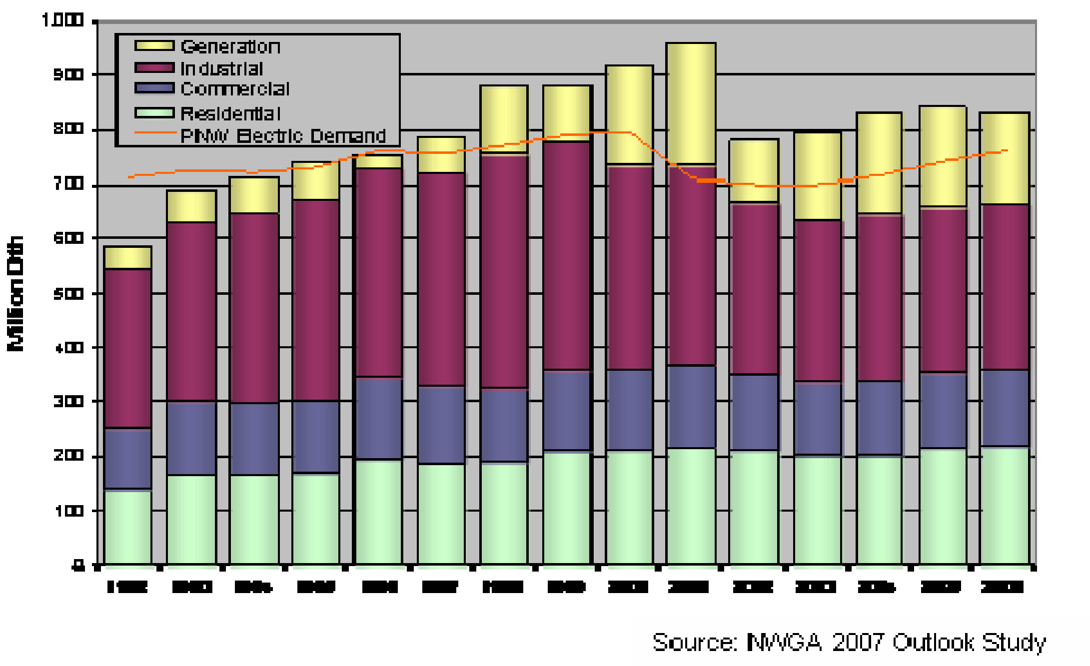
2.1 Regional Energy Needs

2.1.1 Trends in Natural Gas Demand

Strong economic growth continues to increase demand for natural gas in the PNW. The region's total gas consumption has exhibited consistent growth with the Northwest Gas Association ("NWGA") projecting an annual average growth of 1.9% and a cumulative projected growth rate of 7.2% by 2012[4]. Figure 2-1 depicts the historical demand for natural gas in the PNW. The chart shows regional gas consumption is climbing back to levels experienced prior to the 2000/01 energy crisis. Recent past and expected future growth is primarily being driven by the residential and power generation sectors.

[4] NWGA 2007 Outlook Study

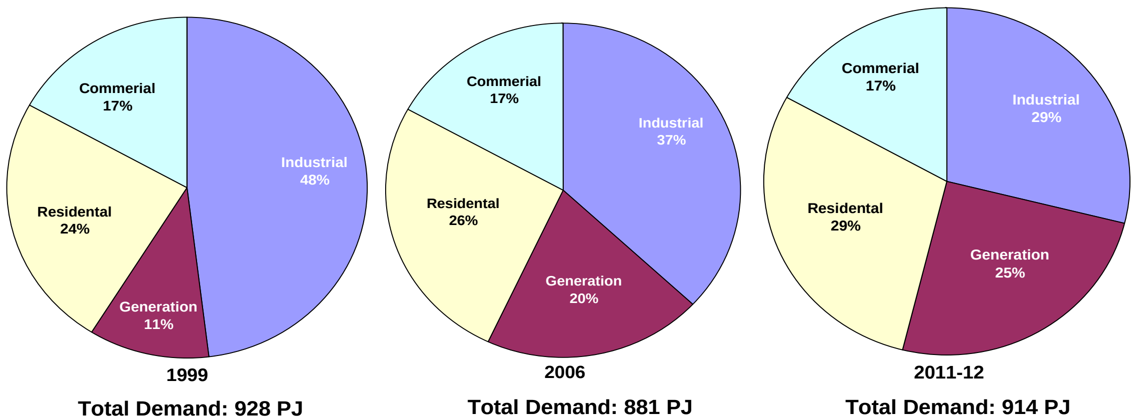
Figure 2-1 Continued Growth in PNW Demand (Source: NWGA 2007 Outlook)



The fundamental change in regional demand relates to the changing customer mix and consequent increase in weather-dependent load. Figure 2-2 compares the historical customer share of annual regional load to future expectations based on NWGA 2007 Outlook demand projections. The chart shows that the residential and electricity generation sectors are projected to make up 54% of total annual demand in 2011/12 compared to 35% in 1999.

The permanent reduction in industrial demand combined with higher growth rates in residential and generation demand imply future regional peak demand is expected to increase more rapidly than baseload demand. The continued growth in customer additions and consequent increase in peak day and annual energy demand is a common projection in the integrated resource plans of regional utilities.

Figure 2-2 Changing to a Weather-Dependent Highly Variable Load

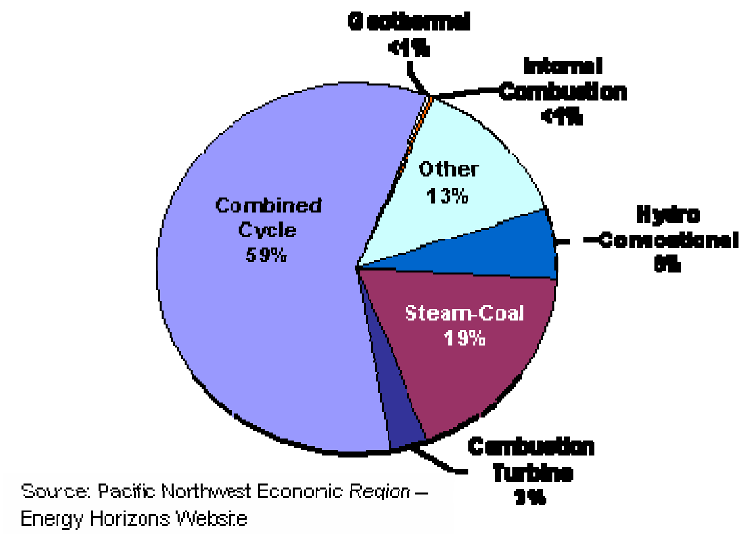


Source: NWGA 2007 Outlook Study

The use of natural gas for electric generation in the region is expected to increase. The NWGA expects natural gas to play a significant role under new energy policies targeting greenhouse gas emission reductions. Electric utilities are challenged by the limited availability of commercial cost-effective utility scale resources that meet reliability, cost effective, and environmental standards. It is anticipated natural gas-fired generation will be used for wind integration, to meet incremental capacity and energy needs, and to mitigate risks associated with using baseload coal resources.

Figure 2-3 provides a summary of generation resources expected to be added during 2005 - 2014. The addition of incremental resources, of which 58% is natural gas-fired generation, imply future resource deficiencies and convergence of energy markets as electric utilities increasingly rely on natural gas and associated infrastructure to meet their resource requirements.

Figure 2-3 Gas-Fired Generation Part of Meeting New Energy Policies



3 SUPPLY UPDATE

3.1 Production

The PNW has access to supply from the Western Canadian Sedimentary Basin ("WSCB") and the US Rocky Mountains ("Rockies"). These production basins represent a significant supply source in North America having approximately 99 trillion cubic feet ("Tcf") of proven reserves and an ultimate resource potential of 500 Tcf[5].

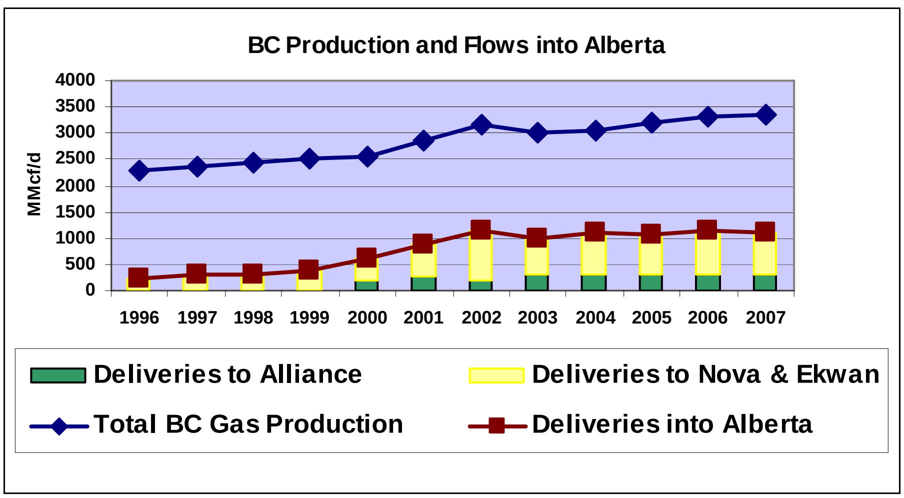
The growth in western production has generated increased competition for supply from other North American markets. While recent pipeline infrastructure developments such as Alliance and Rockies Express ("REX") provide producers opportunities to access alternative markets to maximize returns, regional PNW utilities are challenged to secure long term cost-effective supply resources. Figure 3-1 shows the historical growth in British Columbia gas production and increased supply to the Alberta market. This diversion of gas to Alberta affects supply liquidity at the western trading points of Station 2 and Huntingdon / Sumas, and changes the costs and utilization of existing regional infrastructure.

5 As of December 31, 2005 – see Appendix C, NWGA Outlook Study p.9-10.

Production from the Rockies continues to increase as illustrated in Figure 3-2. The significant growth in production combined with lagging pipeline development has resulted in regional utilities south of the Canada/US border shifting their gas procurement from Northern BC to the Rockies. The greater reliance on Rockies production to meet PNW demand affects pipeline flows which in turn has long term implications on access to resources at Huntington.

Although the region has sufficient supply to meet immediate needs, incremental supply is required to meet long term growth in North American natural gas demand. Figure 3-3 provides Energy Information Administration's ("EIA") outlook[6] of the supply mix to meet future US demand. It shows the growth in future natural gas demand is expected to be met with LNG imports, Alaskan and Canadian Frontier gas, and non-conventional resources. While LNG imports are expected to be the marginal supply resource in the US and several facilities have been proposed in the region, the role of LNG imports in the PNW market is uncertain.

Figure 3-1 Diversion of BC Production Growth to Alberta/Eastern Markets

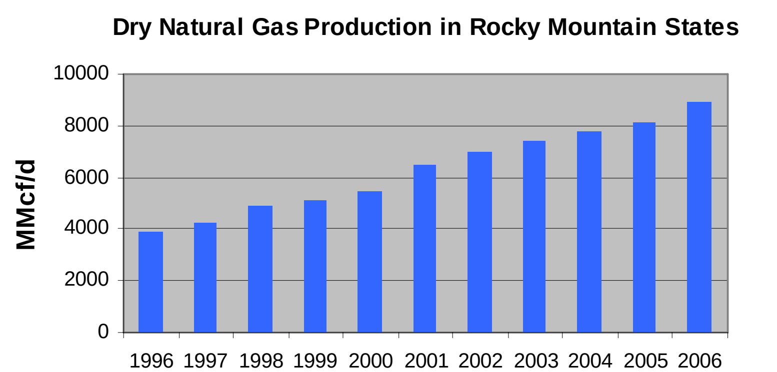


Data compiled from:

1. BC Ministry of Energy Mines and Petroleum Resources (Total BC Gas Production & Flows into Alberta)
2. BC Flows to Nova (TransCanada) and Information from TransCanada
3. BC Flows to Alliance (Daily Throughput Report from Alliance Pipeline website)

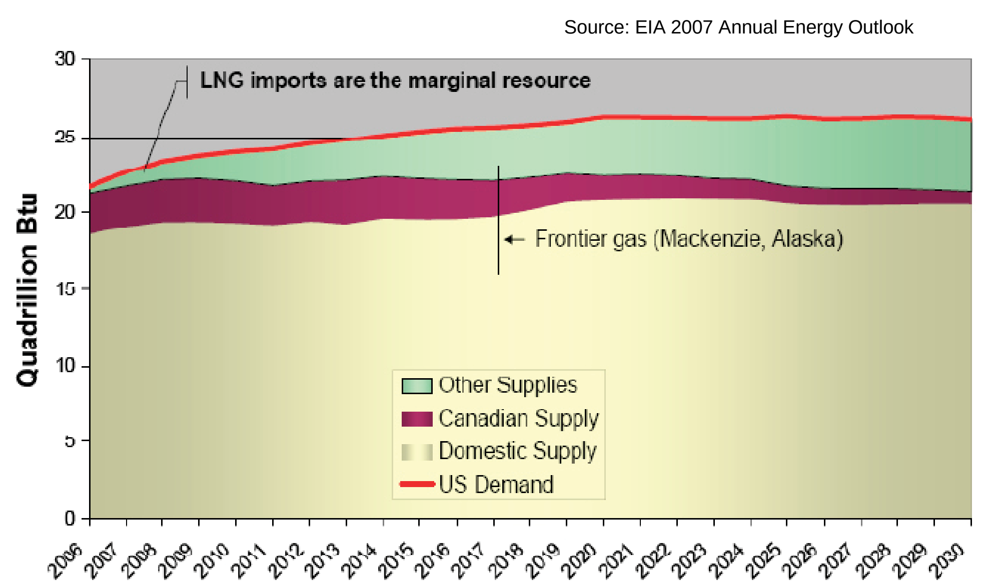
6 EIA 2007 Annual Energy Outlook

Figure 3-2 Increased Rockies Production



Source: Energy Information Administration - Natural Gas Gross Withdrawals and Production, Annual Dry Production

Figure 3-3 LNG imports the Major New Supply Source



LNG (green area) will play a vital role in serving future U.S. demand as cumulative U.S. and Canadian supplies grow only slightly or hold steady. Alaskan gas will provide much-needed domestic supply boost after 2017.

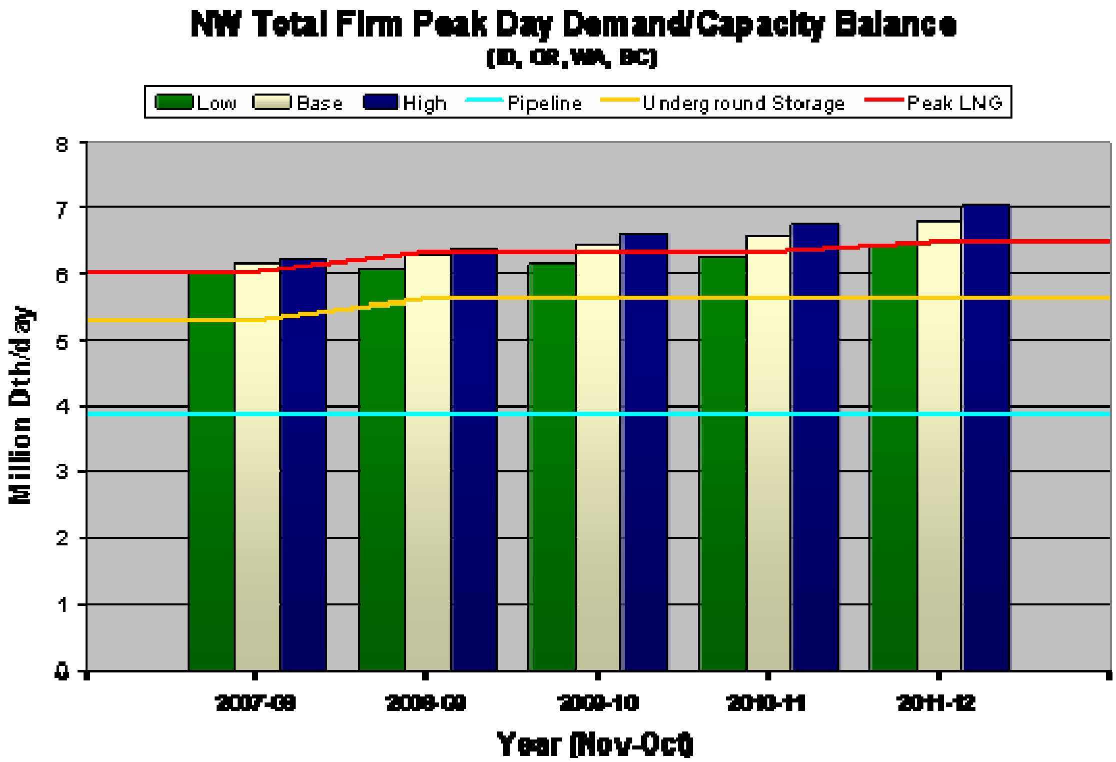
3.2 Regional Infrastructure

The region's natural gas pipeline and storage infrastructure is operating near capacity limits under extreme demand peaks. Figure 3-4 shows the region's infrastructure is expected to be constrained to meet peak day demand and sustained high winter demand by the end of this decade, as projected by NWGA.

The western energy crisis of 2000 and 2001 was a catalyst for permanent closures in both the aluminum and forest products industries throughout the western U.S. Portions of the western forest products industry have continued to struggle economically since that time, with continued closures of mills and other plants.

These large gas users typically had fuel switching capabilities and their supply could be curtailed during periods of high demand and constrained system capacity. Though seldom implemented, this capability provided an additional cushion in system capacity design. Regional demand is again approaching pre-crisis levels; however, this lost industrial load has been replaced with residential and electricity generation demand, both of which are weather sensitive demand. Not only has the Region lost some of the industrial curtailment 'cushion' historically depended on for supply capacity, but the growing demand today is also 'peakier'. These characteristics need to be considered in planning for new regional infrastructure.

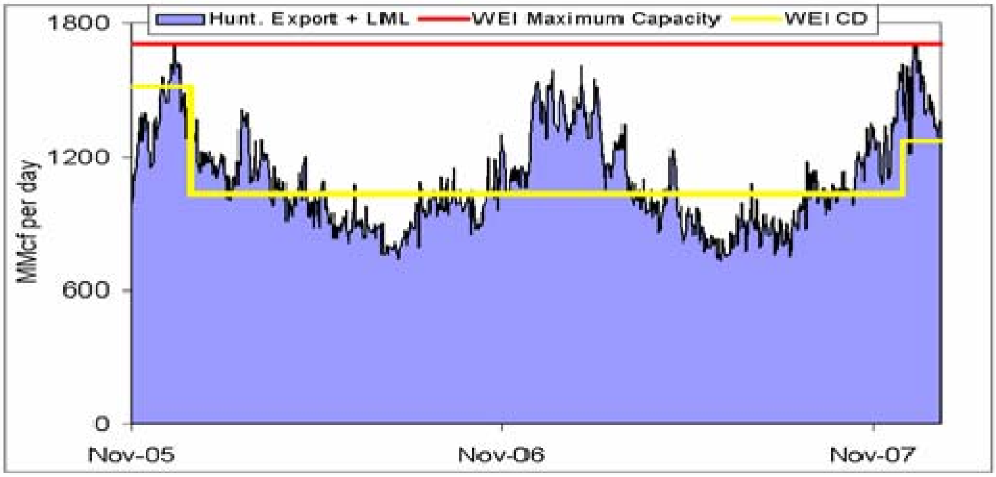
Figure 3-4 Regional Infrastructure Constrained Under Peak Demand Growth Projections



Source: NWGA 2007 Outlook Study

This tight supply-demand balance combined with projected growth in highly variable weather-dependent load, and changing contracting patterns on Canadian upstream pipelines (for entry into alternative markets) creates long term uncertainty in access and cost of existing regional infrastructure. Figure 3-5 demonstrates the difference between utilization and contracted capacity on the Spectra - Westcoast pipeline system. Although contracted firm pipeline capacity declined in 2005, utilization was near maximum limits during peak winter demand in the past three years.

Figure 3-5 Regional Infrastructure Fully Utilized Under Peak Demand



Source: Spectra Energy

The requirement for appropriate natural gas infrastructure to the meet growing and changing nature of demand and facilitate long term resource diversification continues to be viewed as the key challenge of regional utilities. The importance of encouraging infrastructure development that maximizes supply alternatives and fosters alignment of supply-side resources to regional demand with the intent of moderating future gas prices is highlighted by NWGA in its 2007 Outlook Update. Infrastructure development that satisfies this objective will mitigate price volatility and avoid regional price disconnects to the overall benefit of gas consumers in the region.

4 TRENDS IN UTILITY RESOURCE PROCUREMENT STRATEGY

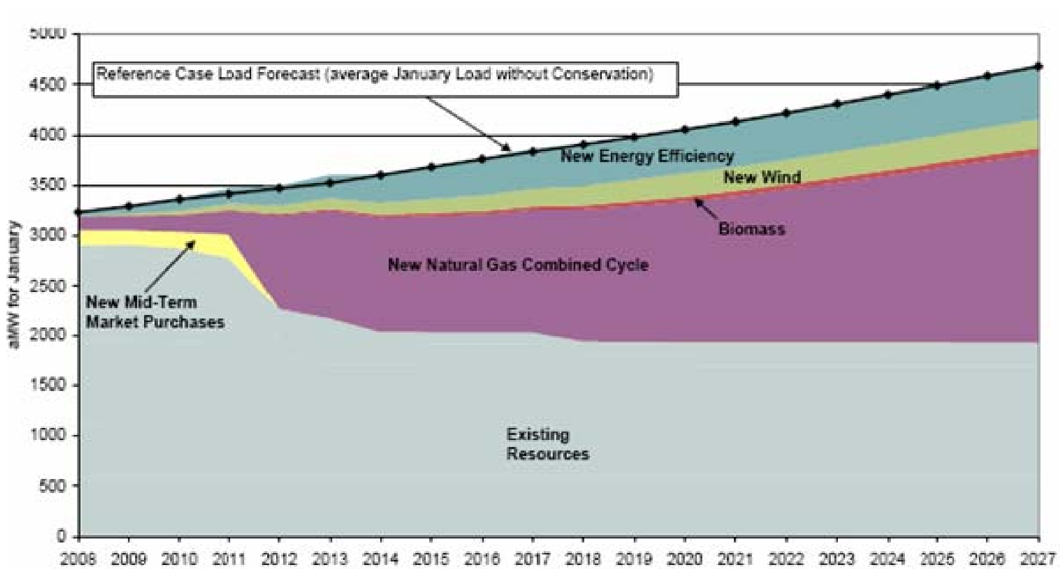
4.1 Drivers of Utility Portfolio Planning

Regional utilities share similar objectives and challenges in the development of a resource portfolio to meet the continued growth in energy demand. Regional electric and natural gas utilities face significant future needs for incremental resources and increasing uncertainty in selecting a supply portfolio that provides the right balance between reliability, cost, environmental concerns and risk. The key issues affecting resource selection strategies include meeting the expected demand growth and adapting to the changing nature of demand, new environmental regulations, uncertainty and limited future supply options.

The demand for energy in the region is changing. Higher growth in weather-dependent demand is expected to result in increased winter peaking demand, the need for sustained peaking capacity, and the emergence of dual season peaking as summer cooling load grows. The integrated resource plans of regional utilities indicate capacity and energy deficits in the following decade.

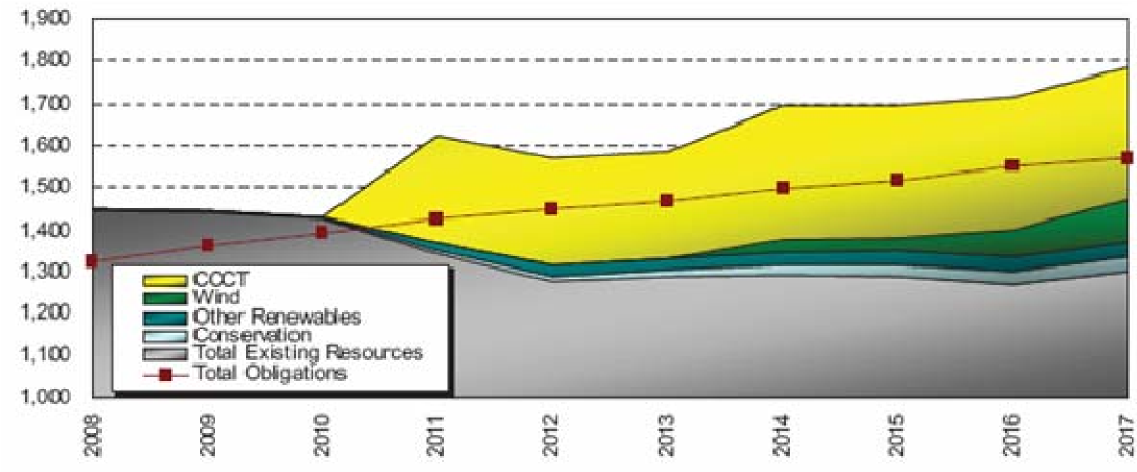
The choice of resources is also affected by environmental regulations. Legislation on renewable portfolio standards and greenhouse gas emissions change the viability of incremental supply options and the risk profile of resource strategies. Figure 4-1 and Figure 4-2 show the preferred electric resource strategy of two regional utilities (Puget Sound Energy and Avista Energy) to meet future demand under the new environmental laws. It shows the resource mix is made up of renewable resources, conservation and gas-fired generation. The significant contribution of natural gas to meet baseload and intermediate electric needs arises from the limited availability and operational challenges of cost effective utility scale renewable resource options and higher economic risks associated with coal emissions.

Figure 4-1 Puget Sound Energy 2007 IRP - Preferred Resource Strategy



Source: PSE 2007 IRP

Figure 4-2 Avista Loads & Resources Energy Forecast with Preferred Resource Strategy (aMW) – 2007 IRP



Source: Avista Energy 2007 IRP

Figure 4-1 and Figure 4-2 also highlight the importance of a diversified resource mix to meet the reliability and cost-effectiveness planning criteria. The integrated resource plans of regional natural gas utilities emphasize the need for long term supply diversification for purposes of maintaining service reliability and improving access to competitive alternatives. Diversity in supply sources and resource options ensures natural gas remains cost competitive at both the individual utility and regional portfolio levels.

5 CLIMATE CHANGE AND UTILITY RESOURCE PLANNING

Climate Change can be defined as the variation in the earth's global climate or in regional climate over time. It involves changes in the variability or average state of the atmosphere over durations ranging from decades to millions of years. These changes can be caused by dynamic processes on earth, external forces including variations in sunlight intensity, and more recently by human activities. In recent usage, especially in the context of environmental policy, the term "climate change" often refers to changes in modern climate conditions.

In a recent analysis conducted by the research firm TNS Canadian Facts, 91 per cent of Canadians agree that climate change is a serious concern and 89 per cent say that immediate action is needed[7]. This survey is an example of how Canadians view the environmental issues as a topic for governments to deal with now and in the future. The environment and its place on the issues list for Canadians have changed in recent years. For many Canadians, the environment ranks along side health care and the economy as the most important issues for government to deal with in setting public policy.

Rising GHG levels are implicated as the primary cause of global warming attributable to the “greenhouse effect”. The rise of carbon dioxide levels in the atmosphere is being attributed to human activity, in particular the consumption of fossil fuels. Consumption of fossil fuels is deeply entrenched in the daily lives of people across the planet. It touches every aspect of modern life from daily transportation needs to electricity consumption in our homes to being a source of raw materials and energy in the manufacturing of products we consume. If governments, following the demands of the public, want to reduce the output of GHG emissions, they will need to develop public policy and regulations that will change individual behaviour and support the development of new technologies that reduce GHG emissions.

GHG emissions, however, cannot be addressed solely within the boundaries of any single political jurisdiction. Instead, to optimize and find solutions that reduce overall GHGs, emission sources and solutions must be examined on a regional or even global basis. The cross-jurisdictional impacts of policies and planning, therefore, need to be addressed. A piecemeal approach in which each jurisdiction develops it own policies, action plans, tax regimes and programs in isolation will be unlikely to result in an optimal solution on GHG emissions overall. An uncoordinated approach on GHG emissions is also likely to have other undesirable impacts on the state and provincial economies by affecting trade and investment patterns and the relative competitiveness of goods and service produced in one jurisdiction relative to its neighbours.

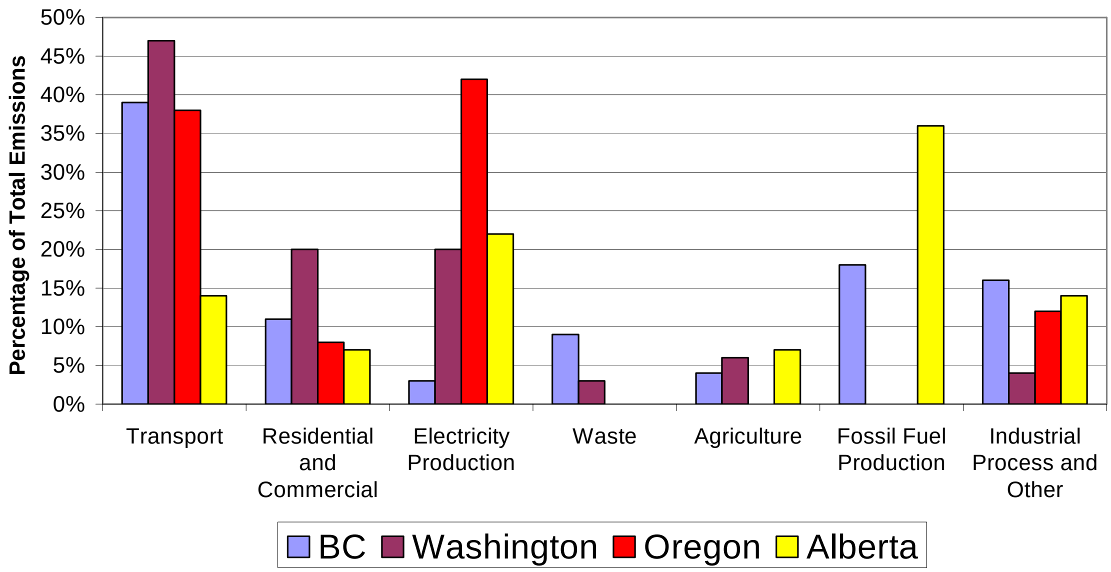
GHG emissions from human activities can be grouped into categories or sectors such as: residential, commercial, industrial, fossil fuel production, electricity generation, transportation, agriculture, and waste. These categories/sectors are used to report and help define the output of GHG emissions for states and provinces, but more importantly they give governments an idea of what regulations or initiatives are needed to reduce GHG output given the mix of GHG sources for any particular state or province. For example, given the information in Figure 5-1, it is clear that BC’s greatest source of GHGs emitted within provincial boundaries comes from the transportation sector. Thus, if BC wants to reduce GHG output in the province a good place to start would be to

[7] TNS Canadian Facts. Global Warming and Green Energy Public Release. July 2007

develop regulations and policies that target the reduction of GHG emissions from the transportation sector.

In addition to transportation, another sector that differentiates provinces and states from one another in terms of GHG output is how electricity is generated in that jurisdiction. In Figure 5-1 the electricity production category clearly illustrates these differences. For example, Oregon produces 40-45% of its GHG emissions in this category; whereas BC produces less than 5% of its GHG output from electricity generation. The reason for this rests with the fact that BC electricity production comes primarily from hydro resources (see Figure 5-2 "Energy Sources for Power Generation (% Share)"). This is an example of how the mix of GHG emissions sources from a state or province can differ due to the particular natural resources available there. BC has abundant hydro resources available whereas Oregon does not. Oregon must look to alternative generation sources other than hydro to meet the state's electricity demand. Oregon has a much higher proportion of natural gas and coal fired generation creating higher emissions in this category.

Figure 5-1 GHG Emissions by Sector (BC, Washington State, Oregon, Alberta)

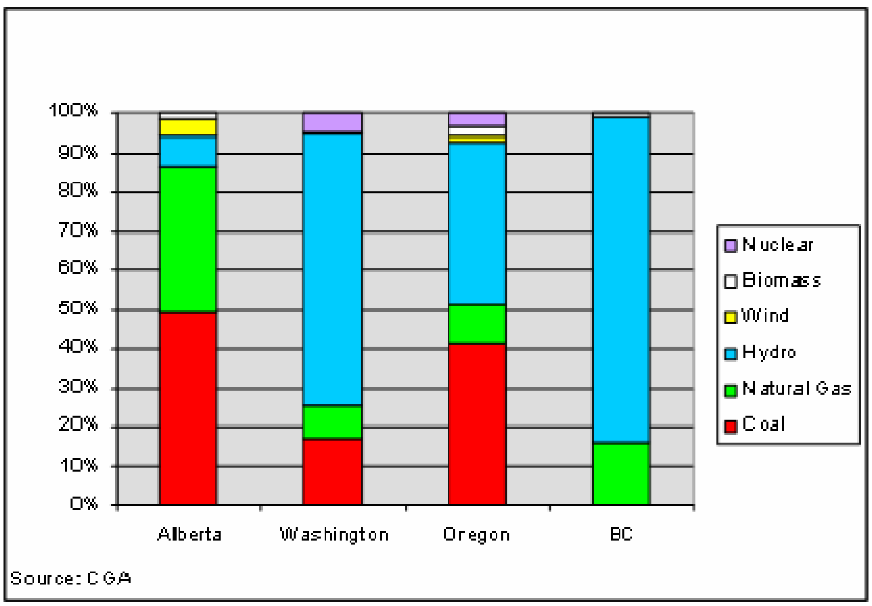


Source: Data is available to the public from various provincial and state government web sites and documents.

Note: If a column is missing for a particular state/province it means the number is zero for the category for that state/province. In some cases the number being zero may have to do with how that state or province classifies and reports the GHG output.

Policies and regulations regarding electricity production differ by state or province. In Oregon or Alberta, policies could, for example, be developed that support the movement from coal-based electricity production to natural gas-fired generation. This would reduce GHG emissions output by 50% for the same amount of electrical output. In BC however, very little domestic electricity production comes from natural gas fired facilities, and none comes from coal. Therefore BC's policies or regulations would need to be quite different in order to reach similar percentage reduction targets. This example shows how, if targets are developed by examining emissions only within a province's or state's boundaries, the public policies in one jurisdiction would be expected to differ from another jurisdiction due to differing sources of the GHG emissions. (See Figure 5-2 "Energy Sources for Power Generation" for more details of how electricity is produced in the Pacific Northwest.) This example also shows that what is considered appropriate in one jurisdiction, may well not be in another from a public perception point of view. In Oregon's case, natural gas is and is perceived to be the "greener" solution than coal. In BC, however, there are no coal-fired generation facilities so natural gas-fired generation is compared to perceived greener hydro-based generation.

Figure 5-2 Energy Sources for Power Generation (% Share)



Source: Canadian Gas Association
Note: BC energy power generation is based on capacity where as the others are based on energy sold.

A second point in this area is that Oregon and Washington could make significant strides towards meeting their GHG reduction targets as part of the Western Climate Initiative ("WCI") by switching from coal-fired generation to natural gas-fired generation. Currently, the total combined GHG output from Oregon and Washington is 155 million tonnes, of which 45 million tonnes comes from coal-fired electricity generation.[8] By converting to natural gas-fired generation, the two states combined would reduce GHG output by 22 million tonnes, which translates into 14% reduction. This is almost enough to meet their WCI reduction target of 15%.[9]

An emerging area of interest in the PNW and elsewhere in North America for achieving GHG reductions as well as broad-based energy efficiency and economic benefits pertains to the promotion of the direct use of natural gas at the end use. Using natural gas in high efficiency end-use applications such as high efficiency furnaces and water heaters is more efficient than using natural gas to fire electricity generation which is then used to for home heating and domestic hot-water. Direct use of natural gas therefore also reduces GHG emissions since natural gas-fired generation is currently the PNW marginal, regional resource. Direct use also avoids future expansion of the electric transmission and distribution systems.

Several direct use studies are being undertaken in the PNW. For example, the Washington Utilities and Transportation Commission recently initiated a review process on the implications and benefits of the direct use of natural gas and fuel switching opportunities in Washington. The Northwest Power and Conservation Council ("NWPCC") is conducting a study on the direct use of natural gas and the economic benefits of fuel switching for inclusion in its 6th Power Plan for the Pacific Northwest Region. The NWPCC conducted a similar study in 1994 and expects the current study to identify significant regional energy savings, economic benefits and GHG reductions as the earlier study did. The BCUC recognized the potential regional benefits of direct use of natural gas in B.C. in its October 26, 2007 decision on BC Hydro's 2007 Rate Design Application. At page 191 of that decision the following statement is made: "The Commission Panel agrees with Terasen that the use of natural gas (as opposed to electricity) for space and water heating in B.C. will make additional energy available to displace coal or gas-fired generation at the margin in the Pacific Northwest."

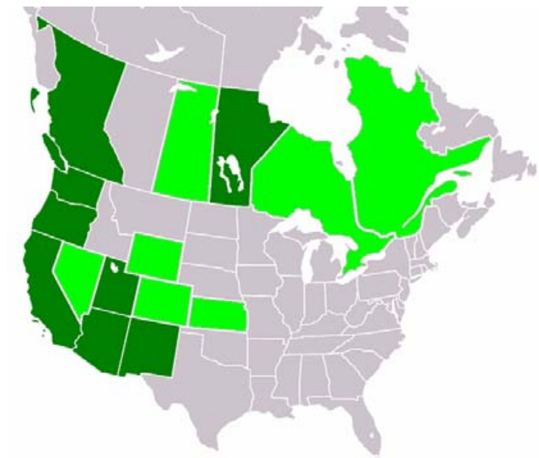
The Western Climate Initiative ("WCI") was formed by 5 US State governments (Washington, Oregon, California, Arizona and New Mexico) in February 2007 to address the growing public concern around climate change and to develop regional strategies to

[8] Washington's Greenhouse Gas Emissions: Source and Trends, December 2006 (Revised 2/12/07) and Inventory and Forecast of Oregon's Greenhouse Gas Emissions, October 31,2007

[9] Western Climate Initiative, "Statement of Regional Goal", August 22, 2007

deal with climate change. In the spring of 2007, Utah and two Canadian provinces (Manitoba and BC) joined the organization. Members of this organization are committed to reduce GHG output by 15% below 2005 levels by 2020 as a minimum[10].

Figure 5-3 WCI: Members and Observers:



Members are in dark green, observers are in light green. Source: WCI web site

One of the interesting issues in the setting up of an organization such as WCI is how this regional initiative will fit into an overall North American or global solution. These states and provinces are working to set goals and policies for their region, but how these regional goals and policies will fit in with the federal, state/provincial, and global polices to reduce GHG emissions is another matter. The potential for conflicting polices could result in the marketplace being sent the wrong signals to promote GHG reductions and lead to suboptimal investment decisions by industry and business. As an example, in recent years California has been leading an initiative along with 19 other U.S. states to implement new and tougher state regulations to limit greenhouse gas emissions from cars. To put these standards into law and enforce them, the states must receive a waiver from the federal U.S. Environmental Protection Agency ("EPA"). To date, this waiver has not been granted by the EPA and on January 2, 2008 the State of California filed a law suit against the EPA in this matter. The result is that there is no new emissions standard in place for GHG reductions from cars and it may be some time before the states and the EPA can come to terms on what the arrangements should be to put this into effect.

10 Western Climate Initiative, "Statement of Regional Goal", August 22, 2007

Many states and province see that there is political goodwill in being ahead of the curve in setting climate change goals, but there is also an economic reality to this trend. This comes from the diversity between jurisdictions on how GHG emissions are produced. If left to a federal body to set policies and regulations, there may be a greater economic cost to pay than if a policy is set locally. For example, in Alberta over 35% of GHG emissions come from the production of fossil fuel that is either consumed within Alberta or exported for consumption elsewhere (see Figure 5-1*)*.

Different policies established to reduce emissions output in this sector may lead to economic impacts on Alberta and the government of Alberta that are quite different than other policies. The Canadian Association of Petroleum Producers ("CAPP") have recommended policies in the past in such documents as the Tax Competitiveness Measure that was submitted in June 2005 to the Saskatchewan Business Tax Review Committee, that promotes the idea of taxing consumption. If this CAPP policy was adopted, the consumers of the fossil fuels would pay the cost associated with the GHG emission for fossil fuel produced from Alberta.

The cost of this tax under the proposed CAPP policy would be spread across all consumers of the Alberta-produced fossil fuel. This is in contrast to having the GHG taxed at source. By taxing at source, the economic impact is felt more in the province of Alberta. Fossil fuel producers in Alberta may end up not investing capital back into Alberta, which in the long term would impact the royalties paid to the Alberta government. This demonstrates how a GHG policy could have undesirable effects on an economy and helps to explain why state or provincial governments do not want to give up control of setting GHG policy.

5.1 Policies and Developments in Other Jurisdictions

Below is a brief description of some of the public policies and regulations for Alberta, Oregon, Washington, California and BC, on how these governments intend to reduce GHG emissions in their state or province. These public policies and regulations are in addition to the commitments these states and provinces have made as members of the WCI, except for the province of Alberta, which is not a member of the WCI.

Alberta:

Alberta is the largest emitter of GHGs in Canada at about 230 million tonnes per year[11], as compared to BC which is fourth at about 67 million tonnes per year. The reasons why Alberta has such a large GHG output comes from the fact that Alberta is a large producer of oil and natural gas in North America and the fact that a large part of Alberta's electricity production comes from coal or natural gas. In Alberta, 72% of GHG output comes from electrical production, fossil fuel production and industrial sectors based on 2004 data.

As early as October 2002, the Alberta government laid out a goal of decreasing GHG emissions intensity to 50% below 1990 levels by 2020. The Alberta government is expected to release a new five year plan in the first part of 2008.

Alberta is the first jurisdiction in North America to have regulations in place to reduce greenhouse gas emissions under the Climate Change and Emissions Management Act. An example of this regulation is that all Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emission intensity by 12 per cent. The facilities have three ways to meet their reductions. They can make operating improvements, buy Alberta based carbon credits or contribute ($15/tonne) to the Climate Change and Emissions Management Fund. By putting this type of regulation forward, Alberta is targeting the areas that can contribute the most to reducing GHG output in the province, which are the heavy emitters: electrical generating plants, large industrial plants, and oil and gas plants.

The Alberta government also has set a target to reduce GHG from government operations by 26% below 1990 levels. Some of the ways that the Alberta government is trying to accomplish this goal are:

1) New government buildings are constructed under Silver Leadership in Energy and Environmental Design ("LEED") standard.
2) 90% of the electricity that is consumed at government facilities comes from green power sources.

Alberta is also making commitments in terms of funding for various renewable and alternative energy sources. For example, for 2007 provincial funding for biofuel initiatives was increased to $41 millions from $ 5 million the previous year.

[11] http://www.ec.gc.ca/pdb/ghg/inventory_report/2004_report/ta12_18_e.cfm

Oregon:

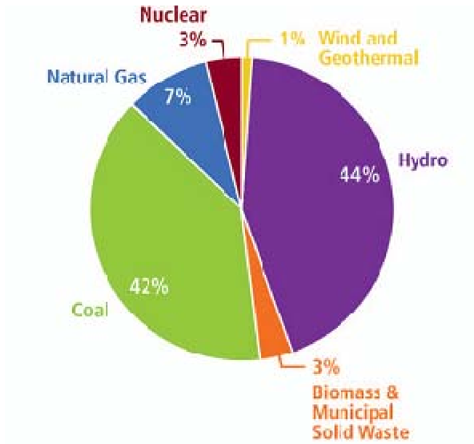
Over the last five years Oregon has started several initiatives to reduce GHG emissions. One of those initiatives is the Oregon Low Emission Vehicle Program which introduces strict emissions standards for new vehicles. Oregon was the eleventh state to adopt California's standards. The rules aim to decrease emissions that cause ground–level ozone, promote zero-emissions vehicles and reduce GHG emissions. The Oregon Department of Transportation can deny registration to new vehicles that do not comply with the standards, which will take full effect in model year 2016. By that time, it is expected that the program will bring about GHG reductions of 30% from vehicles and will have improved average vehicle fuel efficiency significantly.[12] A second initiative of Oregon's is the development of Greenhouse Gas Mandatory Reporting Rules.

In August 2007 Oregon signed into law the creation of a permanent Global Warming Commission. The goal of this commission is to coordinate state and local efforts to reduce GHG emissions. At this time, Oregon has also put into law its goal of reducing GHG emissions by 10% below 1990 levels by 2020.

One of Oregon's key initiatives is to reduce its GHG output from electricity production. Coal and natural gas electricity generation account for 49% of Oregon's electricity production.[13] As an example, shifting from coal-fired generation to natural gas-fired generation in Oregon would decrease GHG output by 50% for every unit of production moved from coal to natural gas. To help in this area, Oregon has mandated that by 2025, 25% of Oregon's electricity supply will come from renewable sources.

[12] State of Oregon, Governor's Vehicle Emission Workgroup Report, November 2005, Page 24
[13] Inventory and Forecast of Oregon's Greenhouse Gas Emissions, October 31, 2007

Figure 5-4 Oregon Electrical Production by Source (2003):



Source: State of Oregon Energy Plan 2005-2007

Washington:

Washington, like Oregon has been addressing climate change for a number of years. The Washington State Energy Office issued a report call "Greenhouse Gas Mitigation Options for Washington State" in April, 1996 that outlined the principle that no single program can stabilize and/or reduce the output of GHGs in Washington State. The State must undertake a broad range of mitigation programs. To this end, Washington Sate has taken significant action to address climate change and they include:

1) 2005 Clean Car Act – requiring certain automobiles to meet tougher emission standards beginning with 2009 models
2) Requiring fuel suppliers to ensure that 2% of the fuel they sell is biodiesel or ethanol
3) Implementing the best energy efficiency standards for appliances
4) Passing a clean energy initiative to increase the amount of energy conservation and efficiency and renewable resources in the state's electricity systems
5) Purchasing hybrid and low emission vehicles for state use

The two biggest initiatives to reduce greenhouse gas emission in Washington are in the transportation sector (45% of total GHG output) and electricity generation (20% of total GHG output).[14]

On the transportation side, Washington is working with other sates to implement new and tougher state regulations to limit greenhouse gas emissions from cars.

In November, 2006 voters of Washington passed the Clean Energy Initiative, an act relating to requirements for new energy sources. This act states that by 2020 sources of electricity constructed after March 31, 1999 at least 15% of these new sources of electricity generation must come from renewable sources.

California:

California is moving ahead on meeting GHG reduction targets in a number of ways, but California is seen as a leader on two fronts when it comes to GHG reduction.

First, California has had a renewable portfolio standard for electricity production since passing legislation in September 2002, four to five years before Oregon and Washington introduced their renewable portfolio standards. Also, the renewable standard legislation target of 20% by 2010 is more aggressive than Washington's target of 15% by 2020 and Oregon's target of 25% by 2025.

California has also been evaluating the acquisition of renewable electricity resources from outside its own borders. A June 26, 2008 article in the Vancouver Sun entitled "California utility looks to BC for green power; PG&E predicts province will have a huge electricity surplus", indicates that California is possibly turning to British Columbia to meet its renewable requirements. This is an example of how solutions may need to cross political boundaries to achieve better results in GHG mitigation and environmental benefits for the region.

Secondly, California has been leading a group that includes 19 other states to be granted authority from the US Federal government to put state laws in place on reducing GHG emissions from cars. Currently, this matter is before the courts.

Others initiatives that California has identified in an April 20, 2007 report entitled "Proposed Early Actions to Mitigate Climate Change in California" are:

14 State of Washington, Department of Community, Trade and Economic Development,2007 Biennial Energy Report, January 2007

1. Low Carbon Fuel Standard
2. Improved landfill methane capture
3. Strengthen light duty vehicle standards
4. Heavy duty vehicle emission reductions
5. Port Electrification

Consistent with the state's GHG emission output profile California is very focused on reducing GHG emission from the transportation and electricity sectors.

5.2 British Columbia

2007 BC Energy Plan

On Feb 27, 2007 the BC Provincial Government released the BC Energy Plan: A Vision for Clean Energy Leadership. The BC Energy Plan lays out 55 policy actions with the intent of ensuring a secure, reliable, and affordable energy supply for all British Columbians, while maintaining our environmental responsibilities. This made in BC solution sees the province moving to eliminate or offset greenhouse gas emissions for all new projects in the growing electricity sector, end flaring from oil and gas producing wells, and putting in place a plan to make BC electricity self-sufficient by 2016.

The highlights of the 55 policy actions are as follows:

- Set ambitious conservation targets, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.
- Ensure a coordinated approach to conservation and efficiency is actively pursued in BC.
- Encourage utilities to pursue cost effective and competitive demand side management opportunities.
- Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.
- Implement Energy Efficiency Standards for Buildings by 2010.
- Ensure self-sufficiency to meet electricity needs by 2016, including "insurance".
- Establish a standing offer for clean electricity projects up to 10 megawatts.
- Public ownership of BC Hydro and the BC Transmission Corporation.

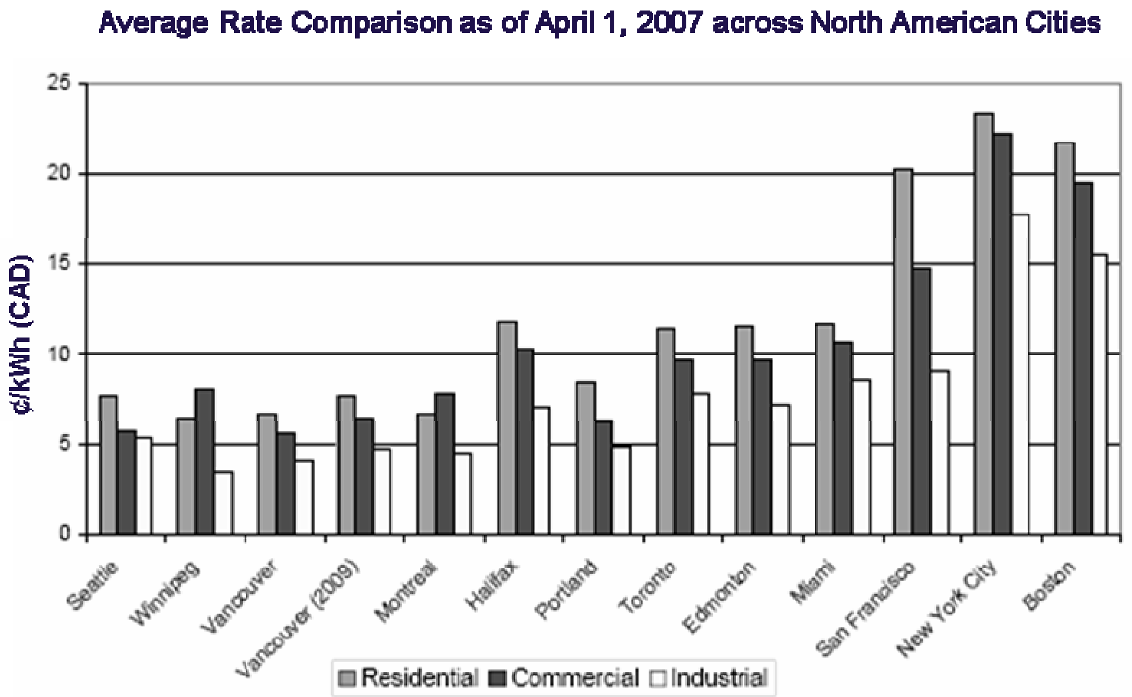
- All new electricity generation projects will have zero net greenhouse gas emissions.
- Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.
- Zero greenhouse gas emissions from any coal thermal electricity facilities.
- Ensure clean or renewable electricity generation continues to account for a least 90 per cent of total generation.
- Review the BC Utilities Commission's roles in considering social and environmental costs and benefits.
- Establish the Innovative Clean Energy Fund to support development of clean power and energy efficiency technologies in the electricity, alternatives energy, transportation, and oil and gas sectors.
- Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half by 2011.
- Best coalbed gas practices in North America.
- Continue to work to lift the federal moratorium on offshore exploration and development and reiterate the intention to simultaneously lift the provincial moratorium.
- Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdiction in North America.
- Support the growth of British Columbia's oil and gas service sectors.
- Implement a five per cent renewable fuel standard for diesel and gasoline.

With the Energy Plan outlining these policies the provincial government of BC has laid a forward path for the province in terms of energy supply and energy efficiency. Thus, it is important for British Columbians to understand the appropriate uses of different forms of energy and utilizing the right fuel, for the right activity at the right time so that the goals of this plan can be reached.

Electricity in British Columbia

In BC, one marked difference from other Pacific Northwest jurisdictions is the small difference between the retail prices of natural gas compared with retail electricity rates. Natural gas commodity pricing for consumers in BC is market-based; whereas a large percentage of the costs making up electrical rates is based on the low embedded costs of BC Hydro's Heritage generation facilities. BC Hydro's electrical rates are among the lowest in North America (see Figure 5-5).

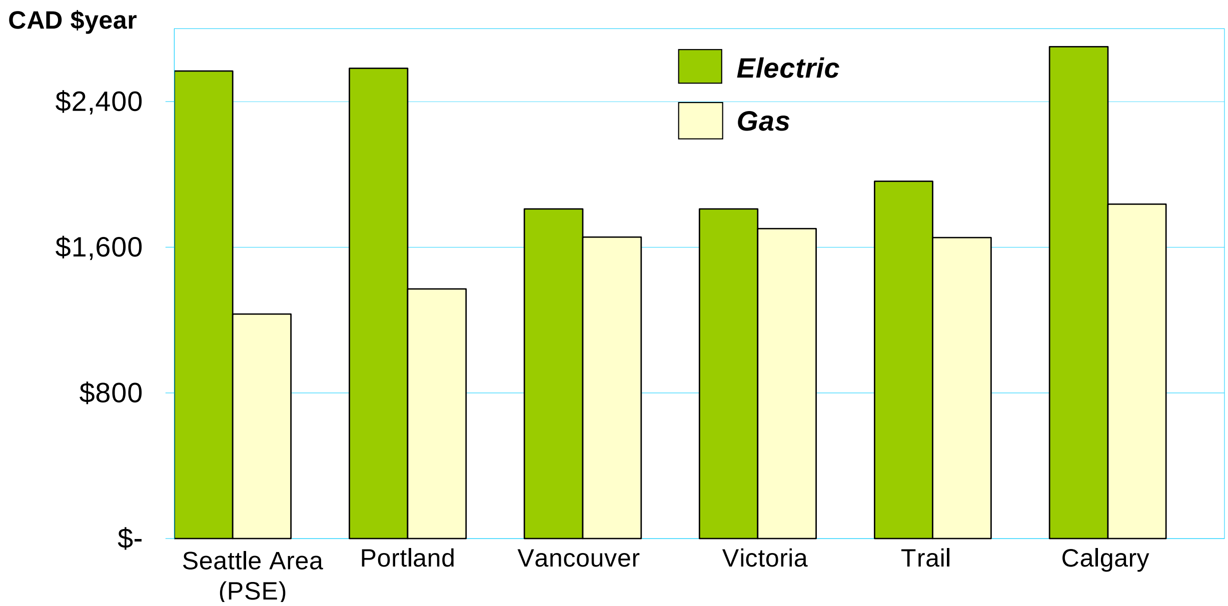
Figure 5-5 Comparing Electric Rates in BC with Cities in Other Jurisdictions:



Source: BC Hydro F2009-F2010 Revenue Requirements Application p. 1-4

The relative cost for residential consumers of natural gas and electricity for BC and neighbouring PNW jurisdictions is displayed in the chart below. The current competitive challenge for natural gas versus electricity in BC relative to other jurisdictions is clearly evident from this chart.

Figure 5-6: Annual Residential Bill Comparisons in the PNW: Electricity vs. Gas



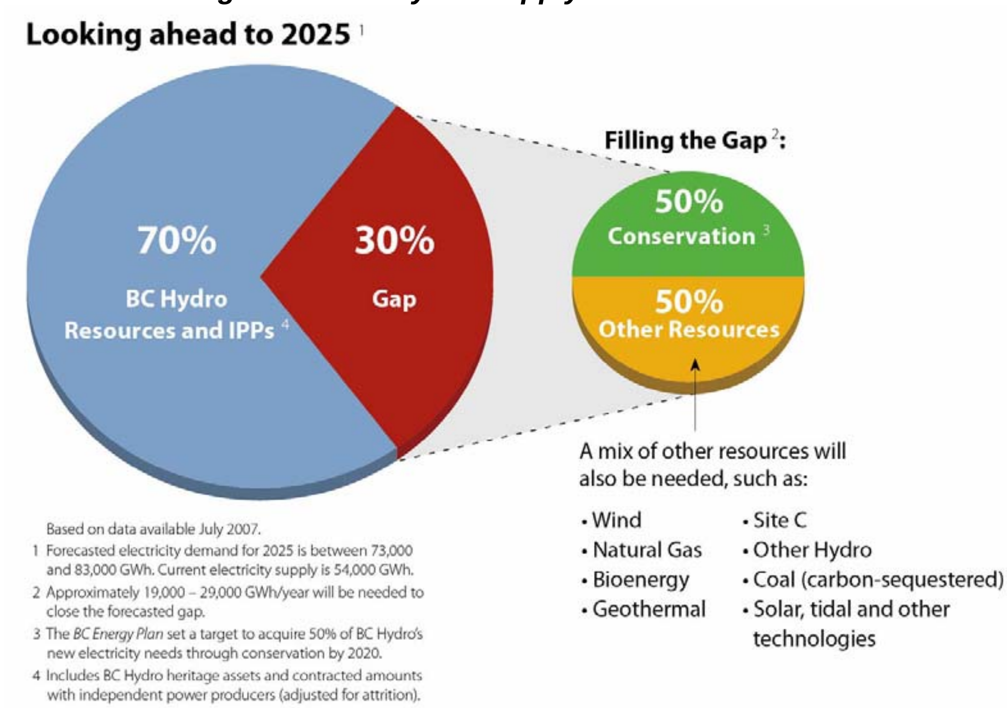
ASSUMPTIONS:
Annual Bill - 110 GJ/year
1 USD - 1.03 CAD Bank of Canada USD Conversion Rate
1 GJ = 9.4782 Therms and 277.78 kWh
The electric rates are 90% efficiency adjusted
Rates include all applicable riders
Other utilities' rates are estimates only

In recent years electricity demand in B.C. has surpassed the supply from Heritage resources and BC Hydro has been a net importer of power from neighbouring jurisdictions as well as contracting for increasing amounts of supply from independent power producers within BC. Going forward an increasing load – resource gap as well as the legislated requirement for electricity self-sufficiency in B.C. will require BC Hydro to acquire additional supply from independent power producers at much higher prices than its embedded costs. As well, BC Hydro and BC Transmission Corporation will need to add new infrastructure to the generation, transmission, and distribution assets to meet the needs of the province.

BC Hydro states in the Peace River Site C Hydro Project report released in December 2007 that by 2025, based on existing resources in its supply portfolio, BC Hydro will be resource short by 19,000 to 29,000 GWh per year (see Figure 5-7). Meeting these resource and infrastructure requirements will cause upward pressure on BC Hydro's rates in the future. For example, on January 10, 2008 the BC Transmission Corporation filed its current Ten Year Capital Plan that set out planned capital spending of $5.1 billion. BC Hydro, in its F2009 / F2010 Revenue Requirements Application, identifies increased capital spending to provide for growth and to refurbish or replace aging assets in its system as a key driver of its requested two-year rate increase.

BC Hydro will also need new supply resources to fill the load-resource gap to 2025. If Site C is one of the options selected to supply a portion of this growing shortfall, BC Hydro has indicated on its website that the early cost estimate for Site C is between $5 - $6.6 billion dollars (Peace River Site C Hydro Project webpage – Frequently Asked Questions). Whether from Site C or smaller independent power projects the cost of new supplies are substantially greater than the average cost of BC Hydro's existing electricity supply. Such cost additions are two examples of how BC Hydro customer rates will be impacted. Site C is expected to provide about 4,600 GWh per year of electricity. Thus, based on the range of BC Hydro's resource requirements, BC Hydro will need to secure enough supply-side or demand-side resources to provide the equivalent of 4 to 6 projects the size of Site C.

Figure 5-7 BC Hydro Supply Position in 2025:



Source: BC Hydro, Peace River Site C Hydro Project: An Option to Help Close BC Growing Electricity GAP; Stage One Review of Project Feasibility, December 2007

How these costs are to be recovered from customers in the future will be dictated by BC Hydro's approved rate design. In 2007, BC Hydro had its first Rate Design hearing since 1991. The BCUC decision on October 26, 2007 dictated some important changes in how BC Hydro's cost will be allocated to rate classes going forward. The key change in cost allocation methodology required by the Commission is that generation and transmission demand-related costs must allocated to the customer classes in a manner that reflects a stronger linkage to the winter peaking nature of the BC Hydro system. The Commission also required BC Hydro to undertake rate rebalancing to move the class revenue-to-cost ratios to 1:1 over three years but this rebalancing requirement was overturned by the Utilities Commission Amendment Act ("UCAA"). Under the UCAA the Commission cannot require rate rebalancing to change rate class revenue-to-cost ratios for BC Hydro before March 31, 2010. After that date rate rebalancing adjustments will be limited to increases in the revenue-to-cost ratios of a maximum of 2% per year. In general the results of the RDA Decision cause a shifting of costs from commercial/industrial rate classes to residential rates in keeping with the principle of cost causation.

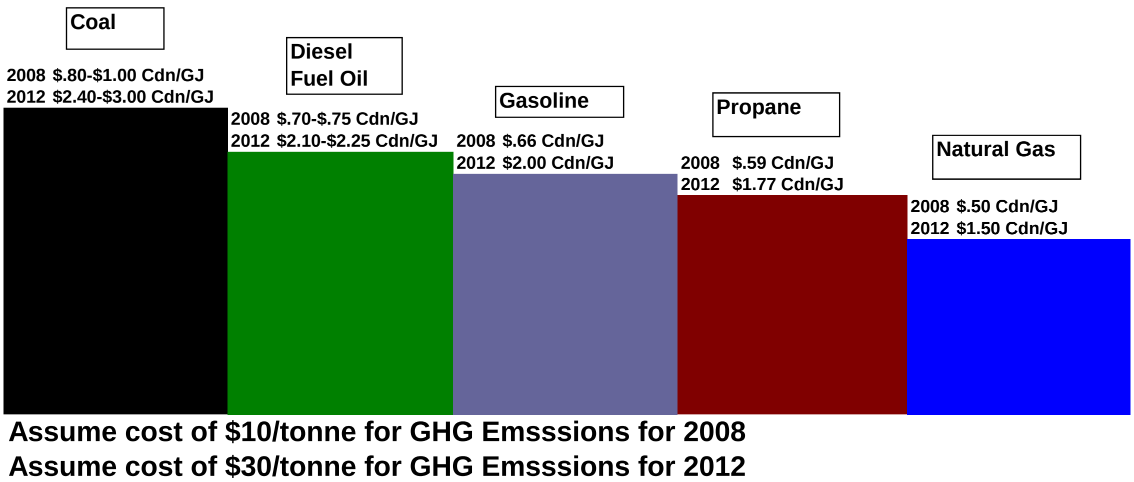
Another matter of debate in the BC Hydro 2007 Rate Design proceeding was the implications of electric space and water heating on energy demand and peak capacity growth in BC Hydro's system and the related implications for GHG emissions. One view advanced in the proceeding was that with the clean electricity and provincial self-sufficiency stipulations in the Energy Plan that using electricity for space and water heating in B.C. would reduce GHG emissions locally. The Terasen Utilities advanced the view that GHG emissions and climate change mitigation are issues that extend beyond the provincial boundaries and should be looked at from a regional perspective. The BCUC recognized the potential regional benefits of using natural gas (and alternative energies) for space and water heating in B.C. in its October 26, 2007 Rate Design Decision. At page 191 of that decision the following statement is made: "The Commission Panel agrees with Terasen that the use of natural gas (as opposed to electricity) for space and water heating in B.C. will make additional energy available to displace coal or gas-fired generation at the margin in the Pacific Northwest." However, the BCUC considered the matter of fuel choice for space and water heating to be a matter of government policy and declined to make a determination in this regard.

In February 2008 BC Hydro filed an application for a residential inclining block rate structure in keeping with its own plans and in response to another requirement of the BCUC Decision on the 2007 Rate Design Application. This rate structure will charge a higher rate for consumption above a specified threshold and is intended to promote conservation. BC Hydro intends to develop other rate proposals in the residential and general service rate classes in order to promote conservation. The UCAA also mandates smart meters for all of BC Hydro's customers by 2012. The availability of smart metering infrastructure will assist in the development and implementation of conservation rate structures. In general, these conservation rate structures will send price signals to customers about the higher costs of new long-term power supply. Conservation rates for electricity will also provide a more appropriate balance between natural gas and electricity rates in the province.

BC Carbon Tax and Other Legislation Changes

On February 19, 2008 the B.C. provincial government as part of the 2008 Budget announced that effective July 1, 2008 all fossil fuel combustion emissions in BC will be subject to a carbon tax. This carbon tax will start at $10/tonne of GHG and increase by $5/tonne each year to $30/tonne by 2012. Figure 5-8 illustrates the cost per GJ of different fossil fuel based their different GHG emissions profile at $10/tonne and $30/tonne.

Figure 5-8 GHG Emission Cost Profile



One energy source that is absent from this emission cost profile is electricity. That is because electricity costs related to a carbon tax depends on the mix of how that electricity is produced. In most jurisdictions the electricity is produced from a variety of sources thus the unit cost associated with carbon tax would vary depending on the supply mix to produce the electricity. In BC, approximately 15% of the electricity consumed in BC is imported electricity produced from other jurisdictions. Whether and how the carbon tax will be administered for this imported power is not clear at this time.

Table 5-1 shows the cost that would be needed to be recovered in BC Hydro revenue requirement if this imported electricity was subject to the carbon tax assuming a carbon tax of $10/tonne.

Table 5-1 Estimated Carbon Tax Cost for Electricity Imported by BC Hydro

GWH's Sold in 2007	Assume 15% Imported	Coal GHG tonne/GWH	GHG Tonnes	$Cdn/Tonne	Total $$$
52,911	7,937	855	6,785,836	$10	$67,858,358
		Natural Gas GHG tonne/GWH		**$Cdn/Tonne**	**Total $$$**
		450	3,571,493	$10	$35,714,925

This example shows that different public policies across different states or provinces can have an impact on how the energy is priced to the end user, which in turn gives the wrong price signal to the consumer, which may impact their behaviour in how they consume energy. Also, this action might result in more GHG emissions for the region as a whole than if policies and regulatory structures aimed at reducing GHG emissions were established on a more regional basis.

In moving the policy items outlined in the 2007 Energy Plan forward the BC Provincial Government in the spring 2008 Legislative Session have introduced the following bills:

1. Bill 15 – Utilities Commission Amendment Act
2. Bill 16 - Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act
3. Bill 18 – Greenhouse Gas Reduction (Cap and Trade) Act
4. Bill 31 – Greenhouse Gas Reduction (Emission Standards) Statutes Amendment Act
5. Bill 27 – Local Government (Green Communities) Statutes Amendment Act, 2008
6. Bill 37 – Carbon Tax Act

The intent of these Bills is to codify various policy items in the 2007 Energy Plan into law within British Columbia. Each of these bills received Royal Assent and was enacted by the end of the spring 2008 Legislative Session.

6 CONCLUSIONS

Climate change and energy are subjects of enormous global importance in the present times. The combustion of fossil fuels provides a large percentage of the overall global energy consumption at the end use and for conversion to another form of energy (i.e., electricity). The combustion of fossil fuels is also the largest contributor to the increasing level of atmospheric GHGs which in turn is considered to be the major contributor to global climate change.

Natural gas is the cleanest burning fossil fuel, producing lower GHG emissions and much lower levels of other pollutants, such as nitrogen oxides and particulates, relative to other fossil fuels. From a regional perspective natural gas is seen as an important part of the future energy resource mix and a contributor to the meeting the climate change mitigation and GHG reduction objectives in various jurisdictions. In electricity production natural gas-fired generation is a preferred resource option to displace coal-fired generation and to provide firm backup to the intermittent renewable generation resources such as wind, small hydro and solar. The direct use of natural gas for residential and commercial applications is also expected to be an important contributor regionally to increased energy efficiency, economic benefits and GHG reductions.

In British Columbia the abundant potential for renewable sources of electricity generation have placed the province in a different set of circumstances. Some have concluded by looking at B.C. in isolation that electricity should be used for space and water heating in the province and displace the use of natural gas in these applications. There are a number of shortcomings of this logic:

- It tends to underestimate or ignore the environmental and social impacts associated with large-scale expansion of renewable power in BC (e.g. the proliferation of transmission lines to connect the renewable resources to the grid, disruption of land use and aquatic systems, etc.)
- It does not recognize that the quantities of end use energy in the province are similar in magnitude for gas and electricity. Any significant shifting from natural gas to electricity would require enormous investment in generation resources and expansion and reinforcement of the electricity grid.
- If natural gas (and alternative energy sources) are used for space & water heating in the province more renewable B.C. electricity will be made available for export to offset fossil-fuel based generation in neighbouring jurisdictions and reduce GHG emissions regionally,
- It undervalues the economic benefits for the province of using the right fuel in the right use. The BC 2007 Energy Plan includes a number of policy actions aimed at responsible expansion of natural gas production in the province. The BC 2007 Energy Plan also promotes energy conservation and efficiency, the development of alternative energy technologies and using the right fuel in the right use. The efficient direct use of natural gas in BC supports all these objectives and will avoid the misuse of the province's valuable electricity resources in lower value end uses such as space and water heating.

It is acknowledged that the topics of Energy Planning and Climate Change discussed in this paper are highly complex and involve large numbers of stakeholders in government, industry and society in general. The intent of this discussion paper has been to show that energy planning and GHG mitigation strategies need to be developed giving consideration to regional issues and perspectives. A further purpose is to demonstrate that natural gas is an important part of the solution, both regionally and within British Columbia.

2 PLANNING ENVIRONMENT

The opportunities, risks and uncertainties within which Terasen Utilities must plan for the future extend well beyond a review of typical energy commodity markets, rates and competitiveness. This LTRP is being submitted during a time of rapid change in energy technology, market forces, public opinion and related government policy around energy use. Energy consumers are faced with a myriad of energy services and equipment choices and often conflicting information with which to make decisions that may impact their energy consumption for years to come. Terasen Utilities' LTRP must consider all of these factors, inform its stakeholders with an accurate and easily understood account of the planning environment, and make recommendations that provide the best path forward for meeting customer energy needs.

In view of the rapidly changing environment the traditional view of electric and gas utilities providing the energy needs for homes and businesses in fairly defined categories will not be the same going forward. Because of the many influences it will only be possible to assess the competitive position of a fuel or energy source relative to alternatives with any certainty after the fact. Forecast energy prices, the future price of carbon, how energy costs get reflected in customers rates, government energy policies, customer perceptions and actions, capital costs of equipment, and type of technology being installed make it difficult to predict with any degree of certainty on how these factors may influence a fuel or energy source competitive position against another.

This section provides an overview of the planning environment within which the 2010 LTRP has been developed. It begins with a discussion of both conventional and new alternative energy supply and pricing for solutions that can serve the needs of consumers and the competitive environment for these energy solutions. The implications of current and evolving energy and climate change policy at the federal, provincial and local levels are also discussed. Energy diversity, using the right fuel most effectively for the right use, optimizing existing infrastructure and developing energy services that customers want are key guiding principles that are informed by the information contained in this section.

2.1 Energy Supplies and Pricing

There will be enough energy for many years to come to heat our homes, businesses and communities, and fuel the movement of people and cargo throughout the region. The evolution towards more sustainable energy systems and greater use of renewable forms of energy will serve to further extend the life of conventional fuel resources. But where will that energy come from and how much will it cost compared to what we are used to paying and how will conventional sources of energy compare with new alternatives? The answers to these questions are uncertain as the energy industry continues to move through a changing environment.

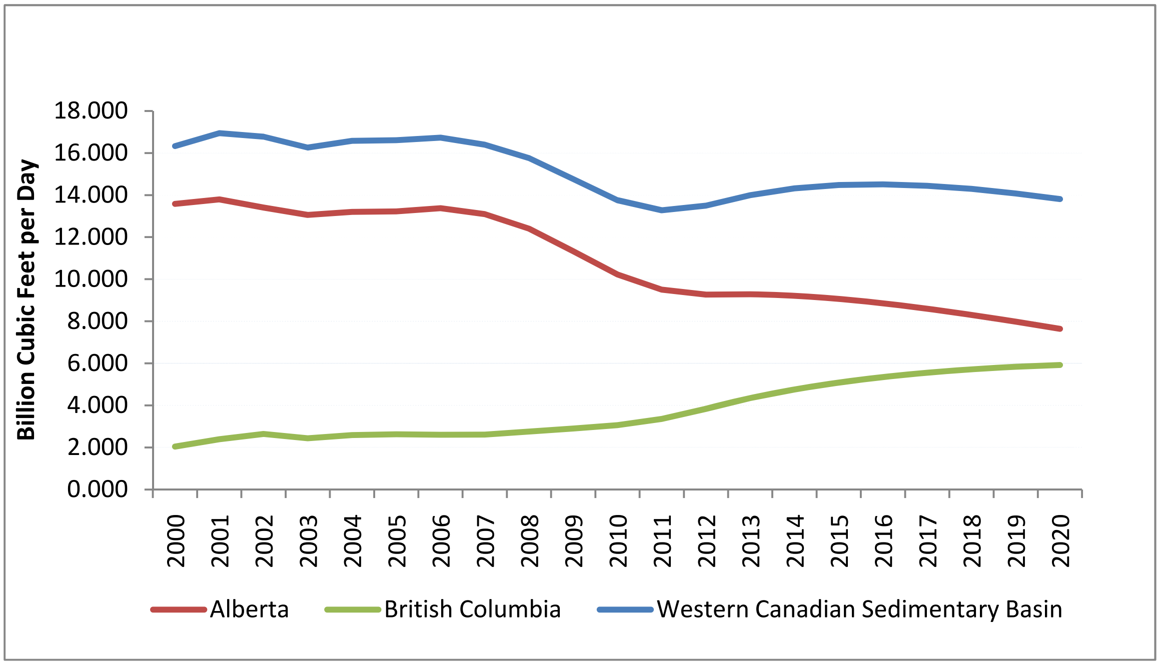
The following discussion explores natural gas supplies, natural gas commodity prices, electricity markets and prices, alternative thermal energy solutions and the price of carbon.

2.1.1 NATURAL GAS SUPPLIES

The North American natural gas resource industry is currently undergoing a major structural shift driven by the development of unconventional supply sources. Recent technological advances in drilling and well completion techniques have allowed producers to access tight sands and shale formations which previously were assessed to be too difficult and uneconomic to produce. The current reserves estimates suggest that there is sufficient supply potential to meet North American requirements for more than one hundred years. However the long term energy outlook shows that these new developments will only serve to offset the decline in conventional resources production rates while overall North American production rates are not expected to increase for several years. Nevertheless, this is a significant shift from previous expectations that North America would face a growing reliance on LNG imports to meet the gap between supply and demand.

In the Western Canadian Sedimentary Basin ("WCSB"), the significant unconventional gas findings in Northeast B.C.'s Horn River and Montney fields are expected to significantly increase B.C. production which will offset declines in conventional production from Alberta as illustrated in Figure 2-1. The WCSB has historically served as the supply source for domestic consumption in B.C. and Alberta, and for export markets accessed by the Spectra ("Westcoast") pipeline, the Alliance pipeline and the three TransCanada Pipelines ("TCPL") systems including the Canadian Mainline, Northern Border and the B.C. Foothills & Gas Transmission Northwest ("GTN") systems.

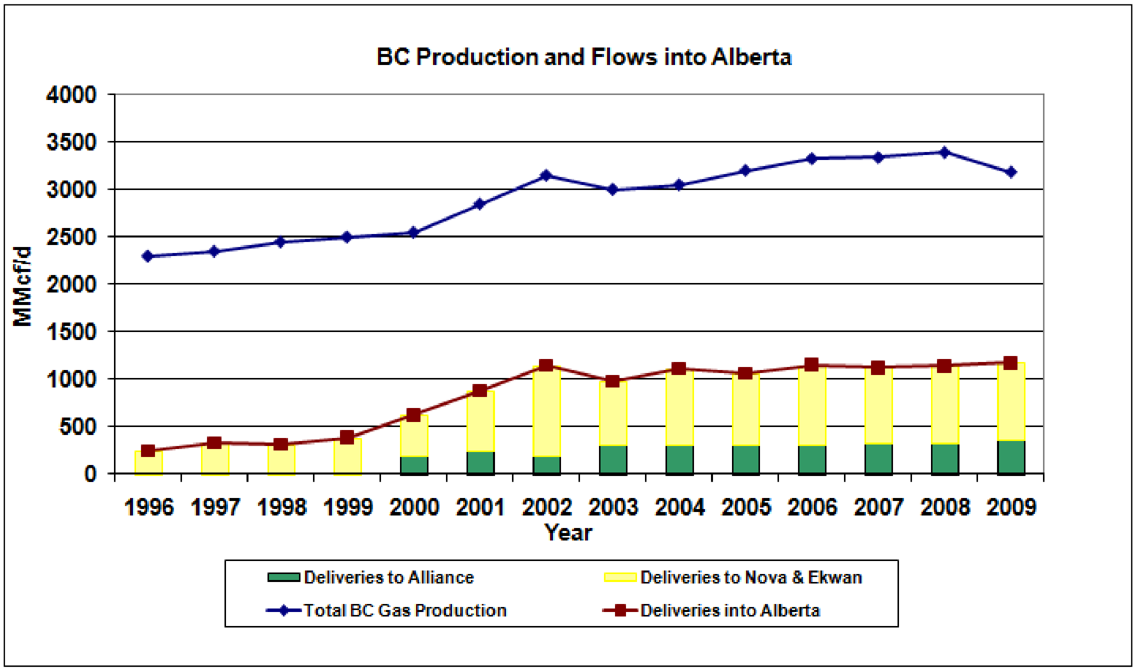
Figure 2-1: WCSB Gas Production History and Outlook



Over the past several years there has been a significant amount of B.C. production flowing east to serve the more liquid Alberta markets and the three interconnecting TCPL pipelines. Since 2001, more than one third of B.C. production has flowed into Alberta as shown in Figure 2-.

In terms of access to B.C. unconventional gas supply for markets served by the Utilities, we will need to compete for access to this supply with other markets including consumers in Alberta where natural gas demand growth is being driven to fuel the oilsands development. The Alberta oil sands currently consume around 1.0 Bcf/d of natural gas and this amount is forecast to more than double by 2017. A portion of the new supply will connect to Spectra's Westcoast system which in turn connects to the Terasen Utilities and PNW markets, however a number of new pipeline projects are being developed which will allow B.C. producers to connect directly to TransCanada's Alberta system, the Alliance Pipeline and other markets (discussed further in Section 6.2). It should be recognized that new connections to markets must be developed in order for the full potential of the B.C. shale gas reserves to be realized. The Utilities are working closely with other regional stakeholders to ensure that these developments will not negatively impact its ability to competitively access supply.

Figure 2-2: Increasing flow of gas from B.C. to Alberta



2.1.1.1 Natural Gas Commodity Prices

Although the supply potential for natural gas is significant, the rate of the development of these new natural gas resources and related infrastructure still depend on North American natural gas prices. Currently, market prices are depressed due to weakened industrial demand, steady production levels and healthy U.S. storage balances. It is generally felt that current pricing levels are too low to sustain long term development of the unconventional gas reserves and continue to offset production declines elsewhere. For example, given the growing gap between natural gas and oil prices, a growing number of natural gas companies now appear to be shifting investment and resources back to oil production, in part motivated by the ability to apply the same technology advances developed in the new gas fields. In addition, future economic recovery, and environmental policies that support coal to gas switching for electricity generation is expected to result in higher demand. As supply and demand come back into balance it is expected that prices will strengthen. Nevertheless the new supply potential within North America has indeed had a moderating impact on long term price forecasts.

Trends in energy costs, particularly in natural gas and electricity prices, influence consumers buying decisions on energy system equipment and fuel choices. Despite the recent focus on renewable energy sources, natural gas and electricity remain the two primary energy choices for consumers in B.C. This section presents a discussion of natural gas price forecasts prepared by independent sources, and then compares the natural gas price outlook with the forecasts for other fossil fuels.

2.1.1.1.1 Natural Gas Price Forecasts

The Terasen Utilities generally utilize price forecasts generated by other industry experts when analyzing the possible future gas market conditions. The short term future prices of natural gas also influence the Utilities' rates that it sets quarterly and annually for the commodity and midstream components of its rate structure. This section provides a long term view to 2035 of natural gas prices as forecasted by independent sources.

GLJ Petroleum Consultants Ltd. ("GLJ") is a private petroleum industry consultancy serving clients who require independent advice relating to the petroleum industry, including the preparation of natural gas and oil price forecasts on a quarterly basis. GLJ prepares commodity price and market forecasts after a comprehensive review of information available to the reported quarter.

Another external source, the U.S. Energy Information Administration ("EIA"), also prepares a range of gas price forecasts using the last 30 years of data including normal weather and storage inventories to generate the price forecasts. The 2010 Annual Energy Outlook ("AEO"), which was released on May 11, 2010, presents long-term projections of energy supply, demand, and prices through 2035. The AEO reference case price forecast is based on an assumption of moderate growth in energy consumption and projects strong growth in renewable electricity generation and use of natural gas in the transportation sector.

Figure 2-3 below, presents natural gas price forecasts from GLJ, EIA Reference case, EIA High Growth case and EIA Low Growth case. It should be noted, however, that these forecasts are based on long term market fundamentals and do not necessarily reflect short term supply and demand imbalance situations which could cause natural gas prices to vary significantly relative to average forecast price levels due to the unpredictability of these imbalance events.

Figure 2-3: Third Party Long-Range Gas Price Forecasts – Henry Hub[15]

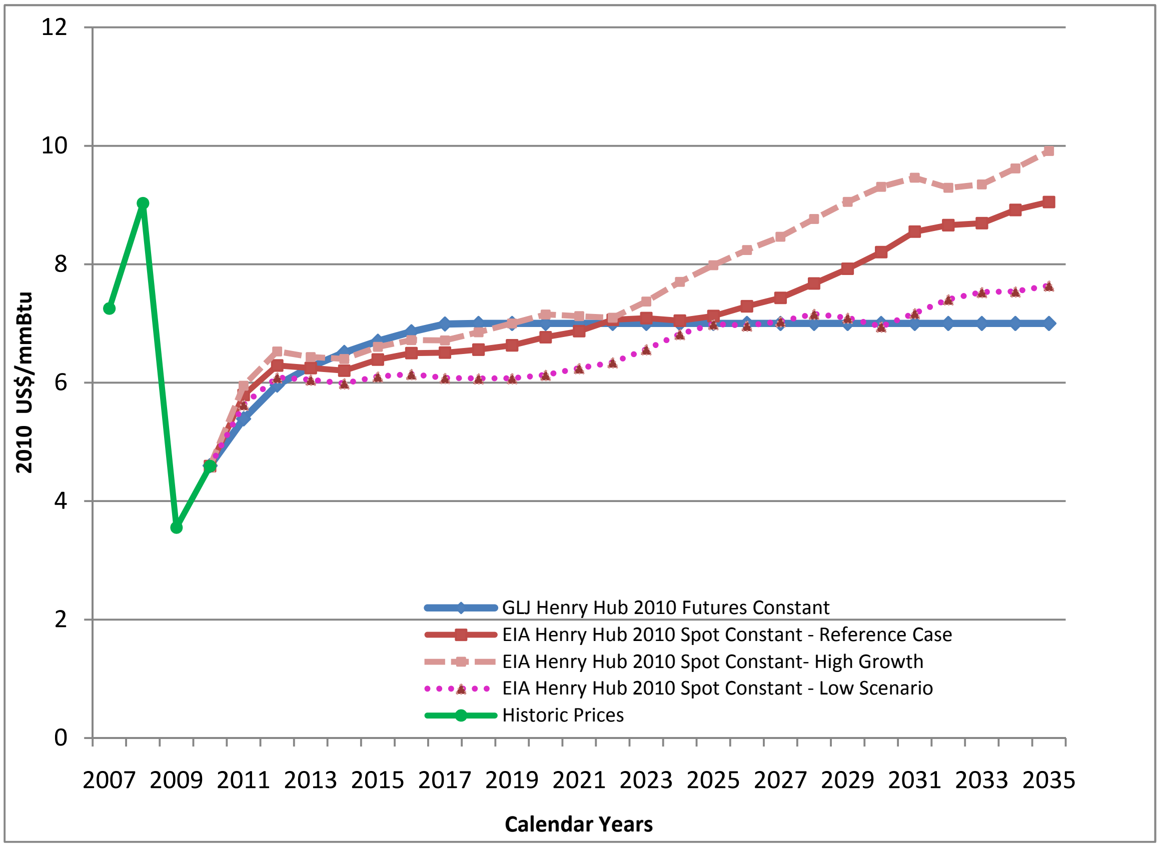
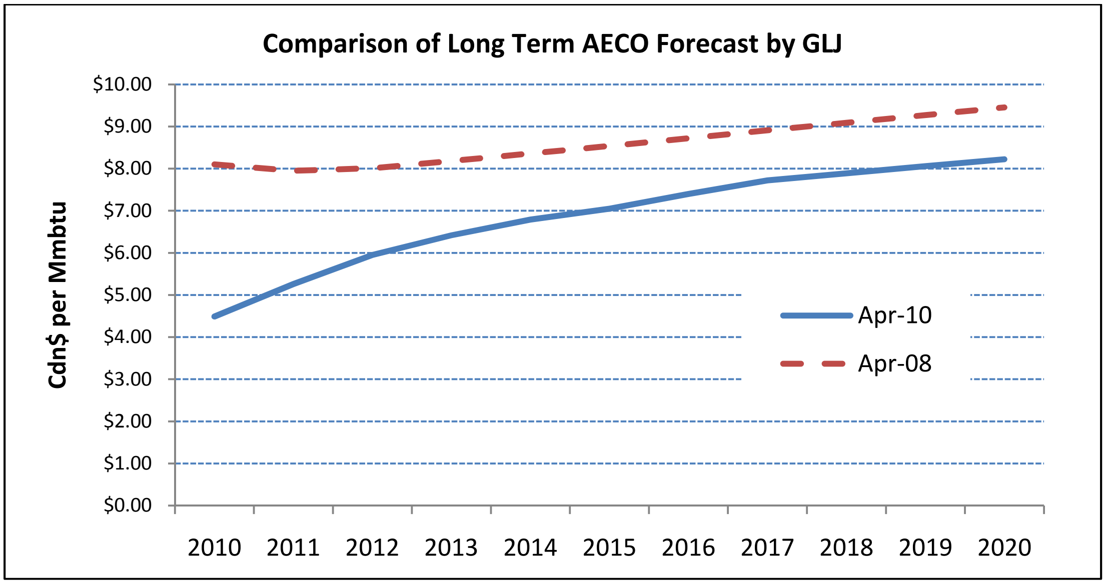


Figure 2-4 which follows, presents the GLJ long term AECO forecast to 2020 and compares that to the same GLJ forecast prepared in April 2008 when the 2008 Resource Plan was being prepared. The comparison reflects the current market expectation that although prices will strengthen as supply and demand come back into balance, recent developments in unconventional gas production and the associated reserve potential has helped to moderate the view of long term prices.

---

[15] The Henry Hub is a benchmark pricing point for natural gas in North America. Natural gas prices in B.C. are priced in some relationship to this pricing point; therefore, the Henry Hub is a proxy for what consumers in B.C. might pay for natural gas over time.

Figure 2-4: Comparison of 2010 and 2008 Long Term Forecasts[16]

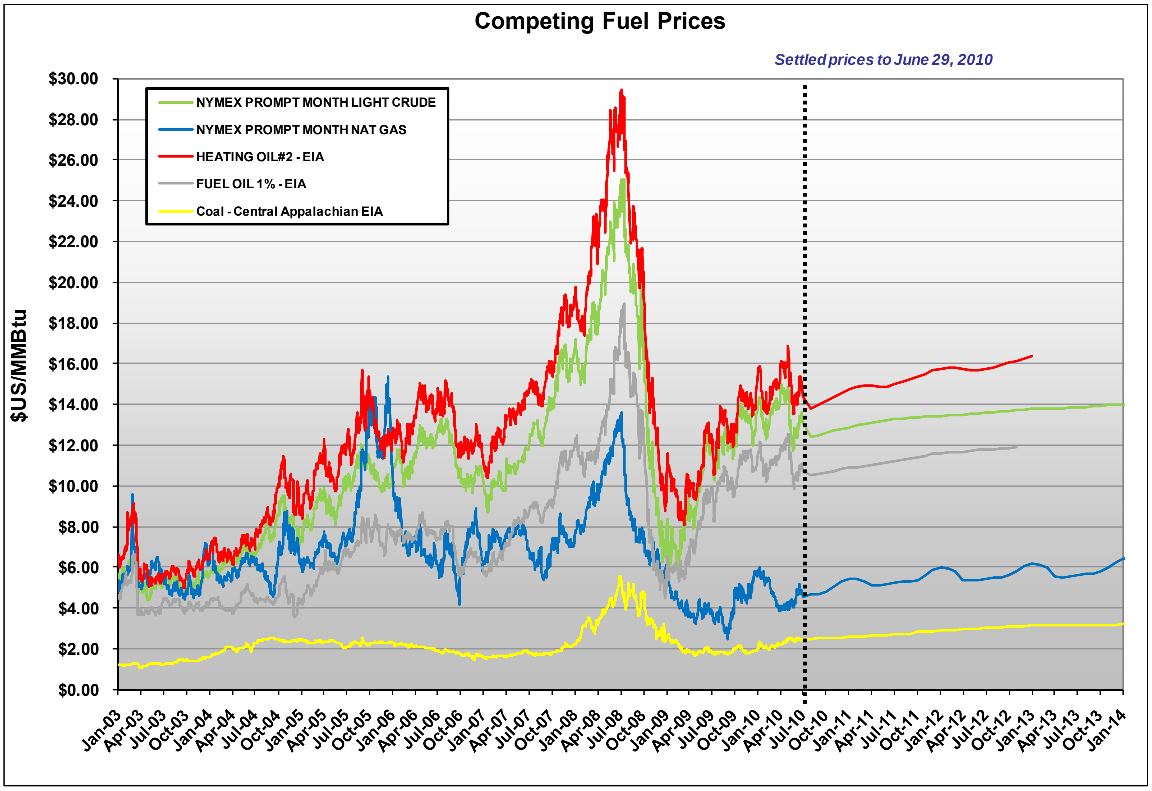


2.1.1.1.2 Natural Gas Prices Compared with Competing Fuel Prices

Historically natural gas prices have been heavily influenced by oil prices due to the short term substitutability of crude oil products with natural gas for industrial and commercial processes and electricity generation. As illustrated in Figure 2-4, price fluctuations in crude oil prices can have major impacts on natural gas prices regardless of the fundamental supply and demand factors that underpin gas prices. This was observed during mid-2008 when crude oil rallied to over $145 US per barrel by July, pulling up natural gas prices to almost $14 US/MMBtu. Oil prices then collapsed to nearly $30 US per barrel by the end of 2008, pulling natural gas prices down with it. Since that time, however oil prices have rallied significantly while North American natural gas prices have remained at lower levels due to poorer shorter term fundamentals. Consequently, the price of coal is becoming increasingly relevant by acting as the floor for natural gas prices due to significant capacity to switch between coal and gas fired electric generation. With stricter environmental regulations placed on coal-fired generation going forward, it is anticipated that this gas-for-coal substitution may occur at higher price levels than in the past.

[16] The Henry Hub is a benchmark pricing point for natural gas in North America. Natural gas prices in B.C. are priced in some relationship to this pricing point; therefore, the Henry Hub is a proxy for what consumers in B.C. might pay for natural gas over time.

Figure 2-5: Historic and Settled Future Commodity Prices – Oil and Natural Gas

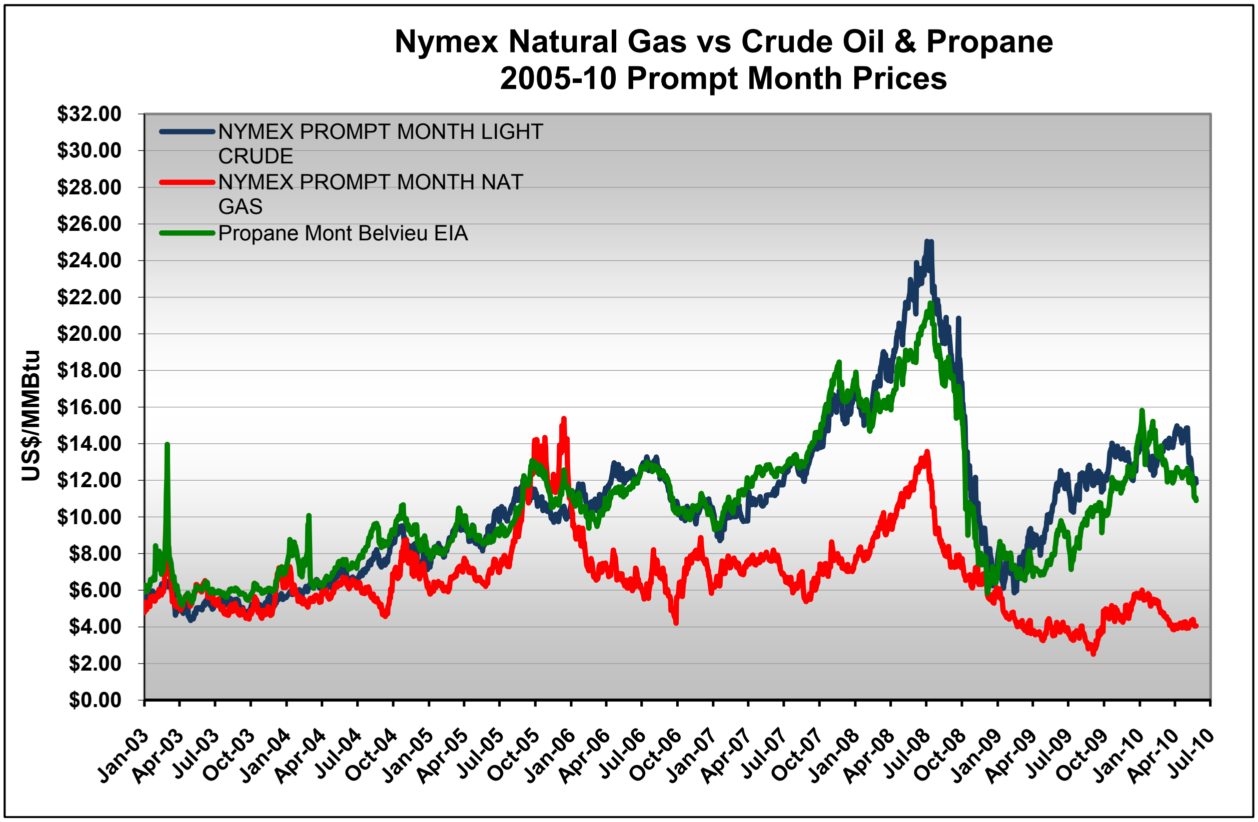


2.1.1.1.3 <u>Natural Gas Prices Compared to Propane Prices</u>

A portion of the Terasen Utilities' customers, primarily in Revelstoke, are served by piped propane distribution systems. Previously, customers in Whistler were served by a propane system. In 2009, the Whistler Pipeline and Conversion Project converted Whistler municipality from a propane system to natural gas.

Historically, propane prices have diverged from natural gas prices and the trend indicates that propane prices tend to follow the higher of oil and natural gas prices. Figure 2-5 shows that this divergence has continued and propane is currently priced higher than natural gas. Based on the tendency for propane to track the higher of oil or natural gas prices the differential between propane and natural gas would be expected to persist in keeping with oil – gas differentials forecast in Figure 2-4.

Figure 2-6: Historic Natural Gas Prices versus Propane and Crude Oil

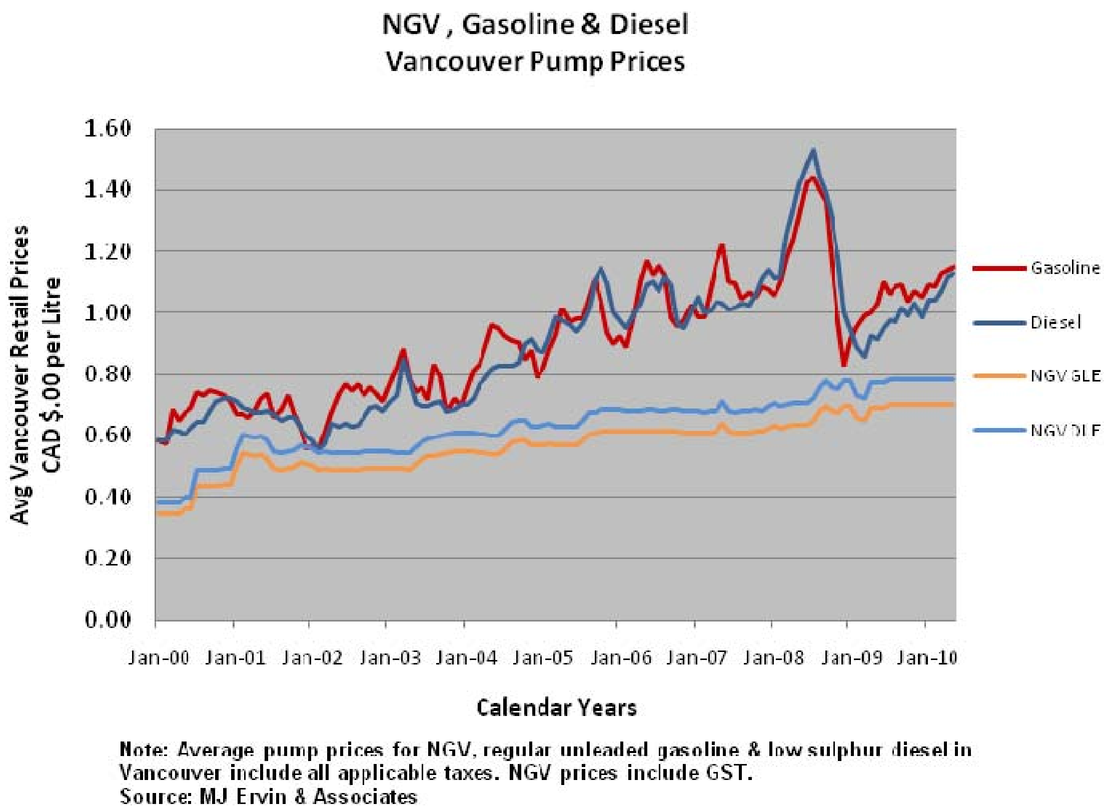


2.1.1.1.4 <u>Natural Gas Price Compared to Diesel and Gasoline</u>

Natural gas usage in the transportation sector is gaining traction in North America, given the abundance of natural gas, its favourable pricing in comparison to oil, which drives diesel and gasoline pricing, and its ability to produce environmental benefits such as lower GHG emissions.

A price comparison of natural gas, diesel, and gasoline for the Vancouver marketplace are outline in Figure 2-7 below.

Figure 2-7: NGV Fuel has a Price Advantage against Diesel and Gasoline



The key points to note from this comparison are:

- With a brief exception in the 2001-2002 timeframe Natural Gas Vehicles ("NGV") has been consistently priced at a level significantly below both diesel and gasoline for the entire decade
- Pricing of NGV in B.C. has been far less volatile than both diesel and gasoline
- NGV presently has a price advantage of approximately $0.35/litre relative to diesel fuel.
- NGV presently has a price advantage of approximately $0.45/litre relative to gasoline

2.1.1.2 B.C. and Regional Electricity Issues

Electricity and natural gas are competing energy sources in a number of consumer end uses such as space and water heating. Electricity is also the energy source for many other end uses such as powering lights and appliances for which natural gas is not an effective alternative. Because of its importance in many aspects of the economy the electricity sector is frequently the focus of public policy initiatives.

In B.C. the provincial government has recently enacted the CEA as a new piece of legislation affecting the energy industry in the province with a primary focus on the electricity sector. The stated objectives of the Province in establishing the CEA are to achieve B.C.'s potential as a green energy powerhouse, to create a framework to achieve electricity self-sufficiency within B.C., to promote economic growth and jobs within B.C., and to facilitate the export of B.C.'s green electricity to other jurisdictions while maximizing the benefits of exported electricity for all British Columbians[17].

The likelihood of B.C. achieving success in these objectives is highly affected by policy in the neighbouring jurisdictions in which B.C.'s exported power is likely to be sold. The electricity industry in each jurisdiction is strongly influenced by energy, environmental and economic government policy at state (or provincial) and federal levels. There are also a number of regional organizations such as, for example, the Western Climate Initiative ("WCI") that are influencing policy and action in the various jurisdictions. The policy context in the western North America jurisdictions is fragmented and that makes it difficult to predict how the various initiatives will unfold and how each jurisdiction will be affected by the evolving areas of energy and climate change policy.

One area that illustrates the policy fragmentation in the west is Renewable Portfolio Standards ("RPS"). Most but not all jurisdictions in the Western Interconnection have an RPS, a requirement whereby the electric utilities within the jurisdictions must acquire a certain percentage of their electricity supply from renewable sources by a certain date. There are differences from jurisdiction to jurisdiction in what resources will qualify as RPS-compliant and whether (and on what basis) renewable resources from other jurisdictions will be considered acceptable. A key issue in this regard for electricity exports from British Columbia to California is that much of B.C.'s hydro-power potential does not qualify under California's current RPS rules. Like B.C., other jurisdictions have drivers other than simply achieving environmental benefits in establishing an RPS. Factors such as fostering economic development within the state or achieving improved energy security and reliability may be of similar or higher importance than attaining environmental benefits.

British Columbia has been recognized as having a large potential in the area of renewable electricity generation. For instance the Western Renewable Energy Zones ("WREZ") Phase 1 Report identifies a large potential in B.C. particularly in the areas of wind generation and hydro generation[18]. However, the WREZ Phase 1 Report also identifies large renewable power generation potential in a number of other western jurisdictions as well. The southwest states of

17 Clean Energy Act, See Appendix A-1
18 WREZ Phase 1 Report, June 2009, Renewable Energy Generation Summary, page 24

Arizona, California, Nevada and New Mexico have large potential in solar thermal generation. States such as Colorado, Montana, Wyoming and New Mexico have large potential in wind generation. The diversity and magnitude of renewable generation potential in the west suggests that there will be competition amongst jurisdictions and resource types to supply the overall renewable requirements in the region.

As discussed further in Section 2.1.1.4 electricity rates in British Columbia are currently among the lowest in North America. However, electricity rates for consumers in British Columbia are forecast to increase over the next number of years. For example, B.C. Hydro issued a ten-year outlook for electricity rate increases as part of its 2008 LTAP proceeding,[19] which indicated estimated rate increases well above general inflation. Among the factors contributing to these rate increases are the need to acquire new supply resources to meet growing load and comply with the provincial self-sufficiency requirements and increased levels of capital spending required sustain the aging system and accommodate load growth. FortisBC has not issued a similar outlook for future rate increases but is facing similar cost pressures and load growth as BC Hydro is. At the same time as electricity rates are forecast to increase the B.C. government has included in the *Clean Energy Act* the objective “to ensure the authority's [BC Hydro’s] rates remain among the most competitive of rates charged by public utilities in North America.” How the outlook for significant rate increases and the objective to keep rates among the most competitive in North America will ultimately play out in terms of electricity rates in B.C. is very difficult to predict. Rate structures, such as BC Hydro’s Residential Inclining Block (“RIB”) rate also affect consumers’ perceptions of energy prices. How future general rate increases or increases in the marginal cost of new power supply will be incorporated in the Step 1 and Step 2 rates of the RIB rate structure (or other conservation rate structures) is also uncertain at this point in time.

2.1.1.2.1 Electricity Generation

Electricity provides approximately the same share in B.C. of the end use energy market as natural gas[20]. B.C.’s electricity supply is predominantly a hydroelectric generation system, with over 90 percent of electricity generation being from renewable, low or no carbon sources[21]. The provincial government’s commitment to maintain this high level of electrical generation from clean and renewable resources in B.C. has been reiterated most recently in the *Clean Energy Act* where the objective “to generate at least 93% of the electricity in British Columbia from clean or renewable resources” has been set out.

---

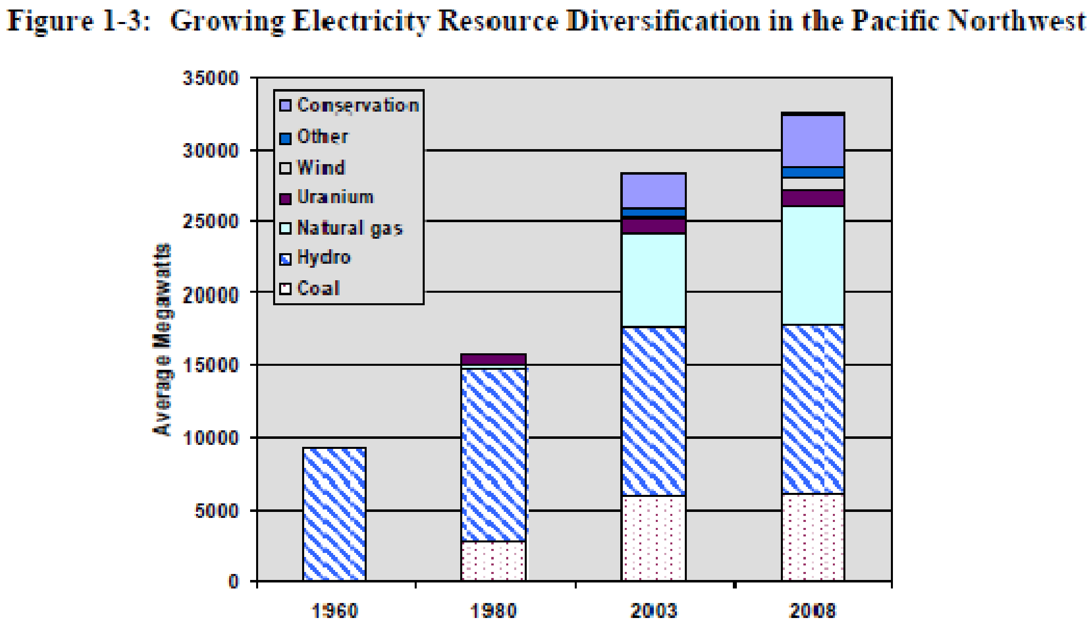
[19] BC Hydro 2008 LTAP, Exhibit B-3, BCUC IR 1.7.1, Attachment 1. A three-year projection of rate increases is also found in BC Hydro’s most recent annual Service Plan which confirms expected increases of similar magnitude in the shorter term.

[20] NRCan Comprehensive Energy Use Database

[21] Ministry of Energy, Mines and Petroleum Resources. “Electric Generation and Supply”. Retrieved from http://www.empr.gov.bc.ca/EPD/Electricity/supply/Pages/default.aspx

By comparison electricity generation in other areas in the PNW region includes large portions that are generated using coal and natural gas. The following chart[22] reproduced in Figure 2-8 was taken from the NWPCC Sixth Power Plan, shows how the mix of electricity generation in the PNW has changed over time.

Figure 2-8: Mix of Electricity Generation in PNW Over Time



With continuing population and economic growth expected in the PNW, and with the expectation of increasing carbon emission costs going forward, the new resources needed to meet growing electricity needs are expected to come from conservation, renewables and natural gas-fired generation. The Sixth Power Plan estimates that 85% of future load growth in the region can be met through cost-effective conservation. Renewables, primarily in the form of wind generation, are being added to meet Renewable Portfolio Standards and to contribute to the load growth not avoided by conservation. Natural gas-fired generation is the likely resource to fill any remaining load-resource gap and to provide firming capability for the intermittent renewable resources. Pursuing these strategies will allow utilities in the Pacific Northwest to make their contribution to the achievement of public policies and GHG emissions reduction goals with natural gas included as part of the solution.

California's electricity requirements are met by generation resources that are approximately 70% of in-state and approximately 30% net imports. About three quarters of California's imported power comes from other jurisdictions in the U.S. Southwest and the balance comes from the PNW. California's Renewable Portfolio Standard of having 33% renewables by 2020 is a large driver of change in the state electricity sector. Overall demand by 2020 is expected to

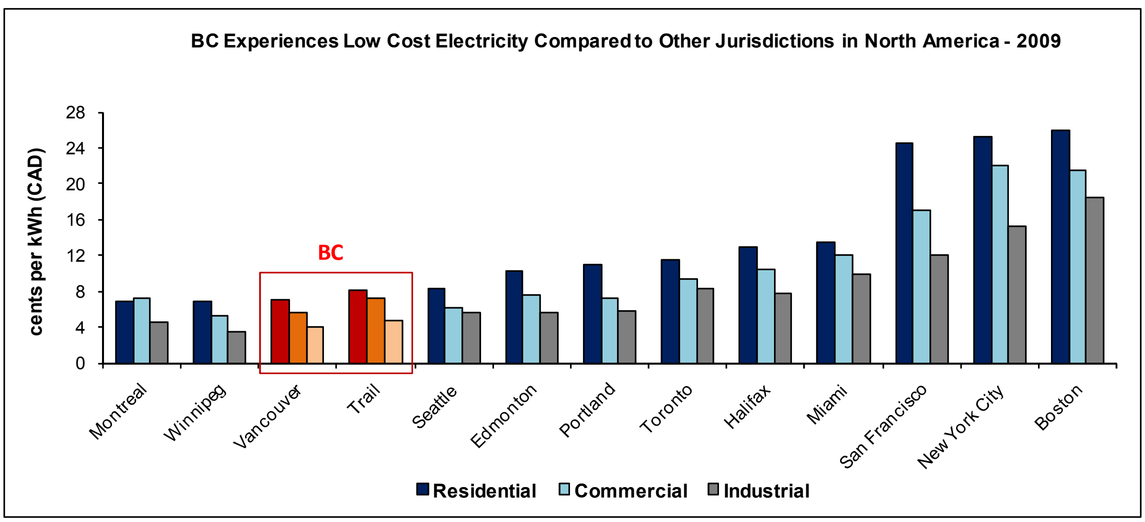
[22] NWPCC Sixth Northwest Conservation and Electric Power Plan, page 1-11

exceed 330,000 GWh suggesting RPS electricity requirements in the order of 110,000 GWh. A California RPS requirement of this large amount is in the order of one and a half to two times B.C.'s current domestic electricity demand. The magnitude of this amount has prompted interest in exports of B.C.'s clean and green electricity to meet California's renewable power requirements. Although there is strong reasons why an export arrangement from B.C. to California would be desirable there are also a number of obstacles to overcome. It is frequently noted that B.C. is a winter peaking jurisdiction while California is summer peaking so taking advantage of excess B.C. generation capability for exports in the spring and summer periods is an obvious benefit of such an arrangement. However a large expansion of electricity transmission capacity between B.C. and California would necessary to accommodate moving significant quantities of electricity. A second obstacle lies in California's current definition of qualifying RPS resources. Much of B.C.'s clean and renewable potential, such as many run-of-river projects are not RPS eligible in California as things currently stand. B.C.'s *Clean Energy Act* has as one of its objectives to open the way for expanded exports of B.C. electricity. Much effort has already gone into studying the export potential and the required transmission expansion but there is still a lot of uncertainty as to how and when all these arrangements will come to fruition.

2.1.1.3 B.C. Electricity and Gas Rates

Electricity rates in British Columbia have historically been among the lowest in North America. Figure 2-9 presents electricity rate comparison information from the most recent version of a study prepared annually by Hydro Quebec. Rates in Trail, B.C. have been added in to represent FortisBC's service territory.

Figure 2-9: Electricity Rate Comparisons



Notes:

- Rates based on Hydro-Quebec's "Comparison of Electricity Prices in Major North American Cities" Effective April 2009
- Trail rates are based on FortisBC electric rates effective January 1, 2010

The B.C. government has made public commitments to keep BC Hydro's rates among the lowest in North America. This has been expressed most recently in the *Clean Energy Act* where one of British Columbia's energy objectives is "to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America". The low electricity rates in B.C. have posed a stronger competitive challenge for natural gas relative to the situation in other jurisdictions. Low electricity rates also create a competitive challenge for the development of alternative energy solutions which tend to be more capital intensive than traditional forms of energy.

2.1.1.3.1 Natural Gas and Electricity Comparison

Figure 2-10 below provides a historical and projected comparison of natural gas bills with the comparable electricity bills. The natural gas bills are based on 95 GJ/year and an assumption of 90% efficiency, while the electricity bills assume 100% efficiency.

In March 2010, BC Hydro requested approval from the BCUC for a general rate increase of 6.11 per cent effective April 1, 2010. BC Hydro's F2011 Revenue Requirement Application ("RRA") is currently under review by the Commission and a decision is expected by the year end.

Figure 2-10: Residential Natural Gas and Electricity Bill Comparison

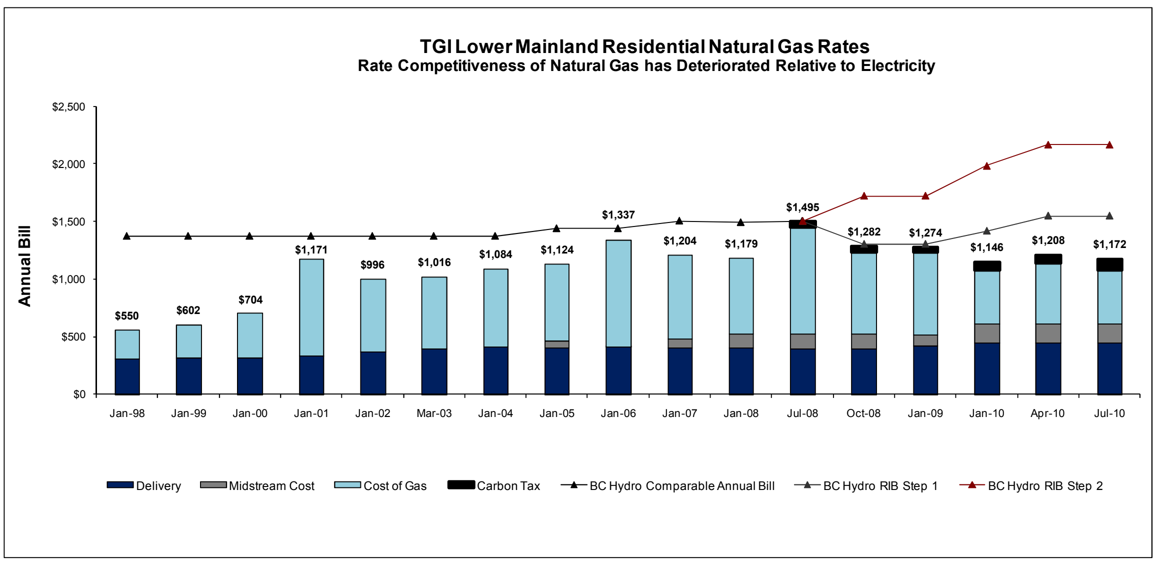


Figure 2-10 demonstrates that while the historical natural gas cost advantage has experienced erosion, natural gas continues to have a modest operating cost advantage relative to electricity. However, the Utilities believe that other factors, such as higher upfront capital costs of a natural gas installation relative to electrical installations and greater rate volatility also figure prominently in the overall competitive position of natural gas relative to electricity. Figure 2-11 demonstrates that natural gas rates need to be lower than electricity rates by approximately $10/GJ to pay back the higher capital costs of a natural gas installation relative to electric baseboards. Also, public perceptions of natural gas as a fossil fuel-based energy source and more restrictive policies driven by climate change concerns (such as possible increases in B.C. Carbon Tax in the future) add uncertainty to the future competitiveness of natural gas going forward.

Figure 2-11: Payback on Incremental Capital Costs for a Natural Gas Heated Home

Payback of Capital Costs (New Construction)	
Space Heating Requirement Only	
New Construction - Home in Lower Mainland (2500 square feet in size)	
Capital Costs for High Efficiency Furnace (90%) and Ducting / Installation	**$ 7,000**
Less: Capital Costs for Electric Baseboards	**(2,500)**
Difference in Upfront Capital Costs	**$ 4,500**
Discount Rate (Cost of Capital)	**6%**
Measurable Life of Furnace	**18**
Amount that has to be recovered annually in operating costs to payoff difference in capital cost	**$415.60**
Add: Furnace maintence costs per year	**100.00**
	$515.60
Energy consumptions for natural gas space heating (GJ's)	**50**
Difference in cost that needs to exist between natural gas heated home and electricity heated home in $/GJ over 18 years	**$10.31**

2.1.1.4 Demand Side Management and Renewable Thermal Energy

As part of its climate action plan to reduce GHG emissions, the Province of British Columbia introduced *The British Columbia Climate Action Charter* involving the Province, the Union of British Colombia Municipalities ("UBCM") and Signatory Local Governments. In support of the Provincial Climate Action plan, the Utilities have implemented a suite of EEC (DSM) programs that help our residential, commercial and industrial customers reduce their natural gas consumption and their GHG emissions. The Utilities' EEC programs promote energy conservation through a variety of programs that focus on the replacement of older low efficiency appliances, conservation efforts through education and outreach programs and implementing renewable energy solutions.

Along with the Terasen Utilities' efforts to promote conservation, the Province's Climate Action plan will bring about changes to building codes, energy policies and other actions that will produce lower thermal energy demands throughout the province as well as substituting traditional energy sources with renewable thermal energy technologies. The Utilities recognize a new forecasting methodology is required to forecast future energy demands in its traditional gas markets as well as new alternative energy developments.

It is important for the Utilities to forecast natural gas demands accurately; and also important to recognize the impact that alternative energy technologies, building design and fuel switching will have upon the overall energy mix and energy demands within British Columbia in the future.

The ability to forecast the thermal energy demand in B.C. through a variety of scenarios will help the Utilities, the Province and other utilities understand the future energy picture. This forecasting will also allow the Utilities to help the Province to understand the effects that potential energy polices will have upon all energy delivery systems.

The province of British Columbia has been in the enviable position of being among the lowest cost electricity jurisdictions in North America. This is a function of the province having a rich endowment of hydro-based electricity generation much of which was developed thirty or more years ago (referred to as the Heritage Resources). Since electricity rates in B.C. are cost based and the low cost Heritage Resources make up the majority of the overall electricity resource portfolio it is reasonable to expect that the cost advantage for B.C. electricity rates relative to other jurisdictions will persist for some time. As discussed above British Columbia also has a very large endowment of cost-effective natural gas resources. However, natural gas is traded in a continental marketplace and the commodity rates that natural gas customers pay are market based. Market influences happening elsewhere such as hurricanes causing production to be shut in on the U.S. Gulf Coast or a cold winter causing abnormal depletion of gas storage inventories affect commodity prices for natural gas consumers in B.C. Although the Utilities continues to believe that natural gas is competitively challenged relative to electricity in B.C. the pricing of natural gas and the benefits of natural gas service have been favourable enough in the past for it to be the energy source chosen for the thermal energy needs of many consumers in the province.

The low cost of electricity and conventional energy in B.C. in turn creates a hurdle for alternative energy developments which tend to be more costly (or at least may appear to be so). Alternative energy developments also tend to be more technically complex than meeting energy demands with traditional energy sources. The Utilities believe that significant growth is needed in alternative energy developments in order for the provincial energy and climate change mitigation objectives to be achieved. Alternative energy developments must form an important component of the energy future along with EEC programs, building codes and appliance efficiency standards if these provincial objectives are to be met. Ingenuity and resources must be brought to the table by all parties - government, utilities, the development community, and energy consumers in order to overcome any cost and technical challenges, and to achieve the desired GHG emissions reductions.

There are many indications of new and expanded activity happening on various fronts in the energy and utility sector. Improving energy efficiency and reducing GHG emissions in thermal applications for the residential, commercial and municipal sectors are being approached from many angles. Expanded utility DSM programs, government incentive programs, building code changes and the expansion of alternative and integrated energy solutions are all examples of approaches being taken to achieve targets in these objectives. Terasen Utilities' own programs include a large increase in EEC programs and expansion into integrated and alternative energy solutions.

Recently there has been a large increase in interest in B.C. in exploring integrated and alternative energy solutions to achieve the energy and climate change goals that have been established in the province. In keeping with their commitments under the B.C. Climate Action Charter municipalities across B.C. are increasingly exploring the viability of establishing district energy systems as a means of reducing greenhouse gas emissions, achieving energy efficiency and reducing waste. Non-government organizations such as the Community Energy Association and Quest (Quality Urban Energy Systems of Tomorrow) are acting as catalysts to spur interest in district energy systems. The province of B.C. has expressed support for the development of district energy systems in a number of ways. For example the province has developed a promotional factsheet entitled the "District Energy Sector in British Columbia"[23], which identifies district energy systems as an efficient way to heat and cool buildings and reduce greenhouse gas emissions. Also the recently established RuralBC website, which provides an easy reference point for communities to access resources and program funding in various areas, notes that funding is available to study the viability of district energy systems in communities across the province and to assist in implementing them[24]. BC Hydro has also recently launched its Power Smart Sustainable Communities Program[25] to support communities in these areas.

2.1.1.5 Carbon Pricing

The future cost of carbon and GHG emissions is another important element in the energy planning environment for this LTRP. While Section 2.3 discusses climate change mitigation policies and legislation in detail a few issues are discussed here with respect to carbon pricing as it will affect energy pricing going forward. The province of B.C. implemented a carbon tax effective July 1, 2008 initially based on $10/tonne of CO_2e and increasing by $5/tonne each July 1 until reaching $30/tonne of CO_2e on July 1, 2012. At the July 1, 2012 level the B.C. Carbon Tax will add $1.49/GJ to the price of natural gas, 6.67 cents per litre to the price of gasoline and 7.67 cents per litre to the price of diesel fuel[26] .

The level of the B.C. Carbon Tax is known with certainty until July 2012 but some parties are suggesting that it is necessary to increase it to a much higher level in order to drive consumer behaviour towards the much lower levels of fossil fuel use necessary to achieve legislated GHG reductions. The outcome of other policy initiatives at the U.S. and Canadian federal level could lead to the introduction of GHG emission cap-and-trade systems or carbon taxes imposed by other levels of government. Overall carbon taxes or cap-and-trade systems will lead to higher costs for fossil fuel consumption. The potential for a much higher cost of carbon in the future

---

23 See link to document at www.empr.gov.bc.ca/MACR/investors/Pages/English.aspx. The document lists eighteen district energy systems in BC either operating currently or under development. Terasen Gas is aware of a number of other district energy proposals, not included in the eighteen that are also under active development presently. Currently, new district energy system proposals are coming to light on a regular basis.

24 See link to program at www.ruralbc.gov.bc.ca/power_smart.htm

25 See http://www.bchydro.com/powersmart/ps_communities.html

26 Gasoline and diesel carbon tax rates were reduced by 5% effective Jan. 1, 2010 as a result of the Renewable and Low Carbon Fuel Standard (see BC Ministry of Finance September Tax Schedule "Carbon Tax Rates by Fuel Type – From January 1, 2010").

adds another level of uncertainty to the selection of energy solutions going forward with the likely outcome unfavourable to natural gas.

2.1.1.6 Conclusion

A simple rate or economic comparison between different energy alternatives may have been appropriate in the past to assess the competitiveness of the various energy forms. Increasingly the future of different energy forms is being strongly influenced by government policy aimed at climate change mitigation and by shifting public opinion caused by environmental concern. The shift towards integrated alternative energy solutions and a heightened focus on energy efficiency and conservation are indicators of these changes. Economics are not the only or even the main driver of consumers' energy decisions. There is a great deal of uncertainty about how these influences will ultimately unfold but it is fair to expect that the place of natural gas will be different in the future thermal energy landscape.

2.1.2 TRANSPORTATION ENERGY

Terasen Utilities believe there are several reasons why looking at the transportation sector is an important area to consider in the development of its LTRP. The transportation sector is the largest source of GHG emissions in B.C., contributing about 36% of the province's total emissions. If British Columbia is to achieve its legislated targets for GHG emission reductions it is clear that reductions from the transportation sector must make a large contribution to these goals. The use of natural gas as a fuel source for vehicles offers the opportunity to displace higher GHG emitting fuels such as diesel and gasoline. The use of natural gas in vehicles also offers the opportunity to develop a local market for a B.C.-produced resource. This local economic development opportunity will displace fuels that are largely imported from outside British Columbia. Thirdly, the development of a larger NGV market in B.C. offers the opportunity to offset natural gas demand decreases in other customer segments such as the residential and commercial sectors. Increasing NGV load also offers benefit to the natural gas system as NGV load tends to be more year-round in nature than low load factor space heating which is the dominant contributor to demand in the residential and commercial customer segments.

The Terasen Utilities believe the best near-term opportunities for widespread adoption of NGV solutions is in the return-to-home, fleet vehicle market, rather than the personal vehicle market. The specific target market for natural gas as a transportation fuel is described further in Section 4.3.

Electric Vehicles ("EVs") are increasingly viewed as a promising low carbon solution for the passenger vehicle market, which is a small portion of the overall transportation fuel market. Currently, EVs are not available in the B.C. marketplace and have limited range for fleet and heavy duty vehicle use. Strong growth in this sector could pose significant challenges for the province's electricity grid. Over the long term; however, the utilities believe that both NGVs and EVs can play an important role in B.C.'s transportation future. It is likely that the market share for Hybrids will continue to grow in the passenger vehicle market and may emerge to take a significant share of the market as battery technologies improve and cost premiums decline. Hybrid vehicles have seen limited introduction into certain heavy duty truck fleet applications and transit bus markets.

The market for biofuels in B.C. is also expected to continue growing, but that penetration will be limited by the economics of biofuel production and emerging awareness of certain limitations with respect to the life cycle impact of biofuels. Emerging issues include the widely differing GHG impact of biofuels depending on the source of feedstock and the land use impact of using agricultural resources (land) for fuel production rather than food production.

This section sets out the market background for the transportation sector in B.C. to set the context for NGV growth opportunities in portions of the market. Additional discussion of the NGV marketplace can be found in both Sections 3 and 4.

- **B.C. Motor Fuels Market Overview**

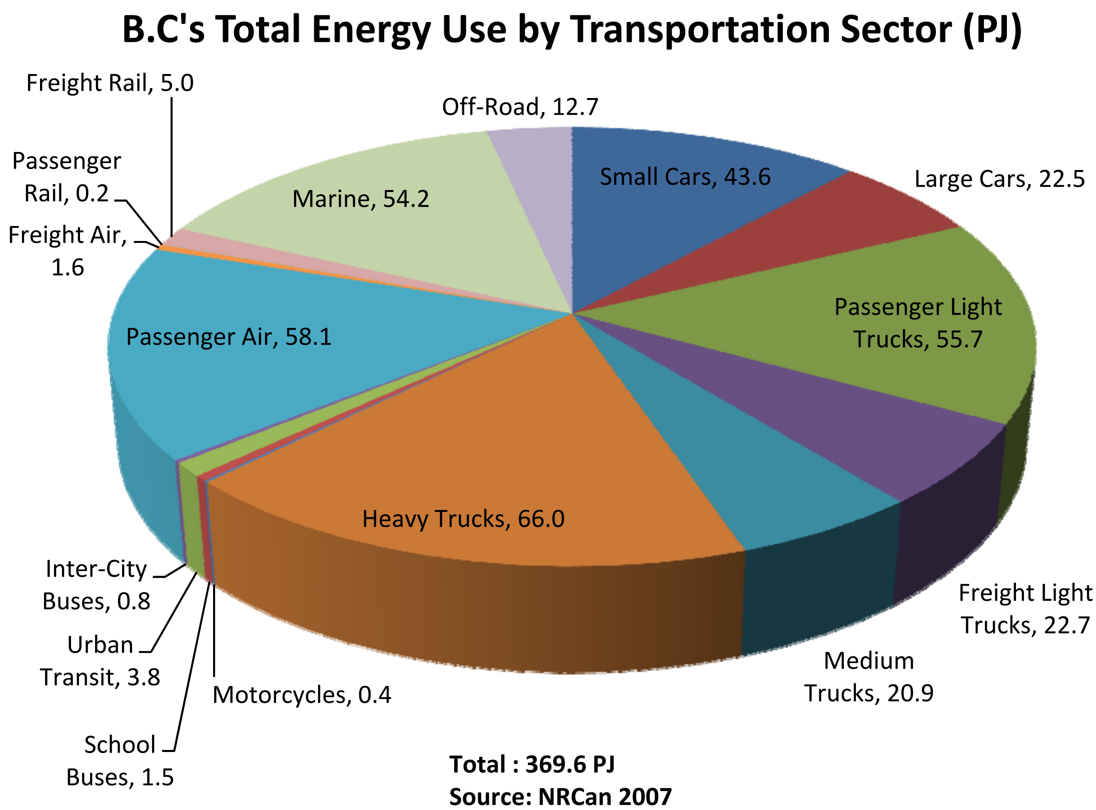
The analysis presented below is based on publicly available data from the Natural Resources Canada Office of Energy Efficiency ("NRCan"). Detailed information on transportation energy use, fuel type, and GHG emissions are given for the years from 1990 through 2007.[27]

- **Energy Use**

The total energy use from B.C.'s transportation sector was 370 PJ in 2007. The figure below shows total energy used by each transportation segment.

[27] Natural Resources Canada, Office of Energy Efficiency, 2007: http://www.oee.nrcan.gc.ca/corporate/statistics/neud/dpa/trends_tran_bct.cfm

Figure 2-12: B.C.'s Transportation Sector Total Energy Use 370 PJ in 2007

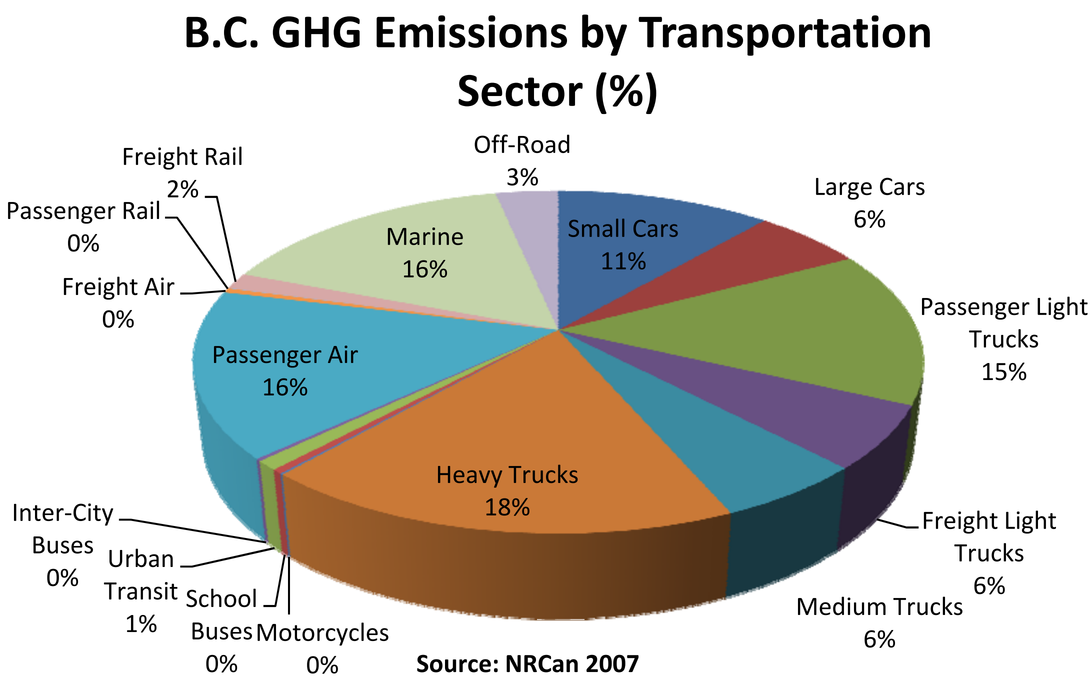


<u>Greenhouse Gas Emissions from the Transportation Sector</u>

B.C.'s transportation sector produced over 25 million tonnes ("Mt") of carbon dioxide equivalents in 2007.[28] The following graph breaks down the GHG emissions by each segment.

[28] NRCan 2007

Figure 2-13: B.C.'s Transportation GHG Emissions by Segment



The Figure 2-13 above illustrates that the trucking (light trucks, medium truck and heavy trucks) segment makes up approximately 44% (or 11.4 Mt) of the total emissions profile. Passenger cars (small and large) represent approximately 17% (4.4 Mt), and marine consists of 16% (4.1 Mt). Data from NRCan indicates heavy-duty NGVs emit 15%-30% less GHG emissions than their diesel counterparts[29]. These sectors represent an important opportunity for the Utilities to use natural gas as a transportation fuel in these high emission sectors to help meet B.C.'s legislated GHG reduction targets.

2.1.3 ENERGY EXPORTS FROM B.C.

The energy sector is one of B.C.'s largest categories of exports, accounting for 27 percent of exports[30]. The province's exports are expected to increase at "a double-digit pace" in the next couple of years as commodity prices rebound and demand from the U.S. recovers. The energy sector in particular is forecast to see a 20 percent growth in 2010 and 17 percent in 2011, a major rebound after a decline of more than 30 percent in 2009[31]. This growth in the dollar value of energy exports is mainly due to increased natural gas prices, forecast to be as much as 40

29 For more detail, please see Section xxx
30 Export Development Canada. "Global Export Forecast: Spring 2010". Retrieved from http://www.edc.ca/english/docs/GEF_e.pdf
31 Export Development Canada. "Global Export Forecast: Spring 2010". Retrieved from http://www.edc.ca/english/docs/GEF_e.pdf

percent higher than 2009) as well the Horn River Basin shale gas formation, and coal production[32]. With anticipated high demand for natural gas, it continues to be B.C.'s most important energy export. In the long term, the construction of a pipeline from the Montney shale gas formation as well as the possibility of an LNG liquefaction terminal in Kitimat will further increase the province's export capacity[33]. B.C.'s significant role in energy markets will be further strengthened by the B.C. government policies and initiatives, such as the *Clean Energy Act*, promoting the development of an electricity export market. Moreover, as mandated by the B.C. Energy Plan, the Net Profit Royalty Program stimulates development of natural gas and oil resources that are not economic under previous royalty programs by sharing the capital risk of successful developments and recognizing the long-lead times associated with these developments.

2.2 Energy and Climate Change Policy and Legislation

Energy policy at all levels of government is increasingly focused on energy conservation and efficiency, clean energy production, and energy consumption behavior aimed at reducing GHG emissions as a means to address challenges imposed by climate change. In recent years, B.C.'s provincial government and municipalities have taken steps to develop targets and action plans to support reductions in GHG emissions. The actions of Canada's federal government, while not (yet) reflected in formal policy or legislation, reinforce this focus on cutting GHG emissions through reducing consumption of carbon based fuels. In the U.S., the change in the federal government resulted in a renewed commitment to clean energy and GHG emissions reductions[34]. Thus, all levels of government across North America recognize that GHG emissions reduction is a pressing need, which gives rise to an increased focus on energy policy and energy issues.

Government energy policies and legislation have a great influence on the direction of how energy will be produced and on the energy choices that customers make now and into the future. This section explores how federal policy in Canada and the U.S., state policy in the PNW, and B.C. provincial government policy and initiatives are all focusing on energy consumers with the common goal of GHG emissions reduction.

---

[32] Export Development Canada. "Global Export Forecast: Spring 2010". Retrieved from http://www.edc.ca/english/docs/GEF_e.pdf

[33] Export Development Canada. "Global Export Forecast: Spring 2010". Retrieved from http://www.edc.ca/english/docs/GEF_e.pdf

[34] There are currently two bills being reviewed by the U.S. Congress, the American Clean Energy and Security Act (the Waxman-Markey bill) and the American Power Act (the Kerry-Lieberman bill), at this time it is not clear which one, or if either, will be signed into law.

2.2.1 FEDERAL APPROACHES TO CLIMATE CHANGE IN CANADA AND THE U.S.

At a federal level both Canada and the U.S. have similar views on climate change policy and GHG emissions reduction objectives. With respect to transportation fuel efficiency standards, Canada and U.S. appear to agree on the path forward.

2.2.1.1 Canada

The Canadian federal government has demonstrated its commitment to participate in international efforts to mitigate climate change by setting energy and environmental policies which, although not legally binding, focus on reducing GHG emissions. The government of Canada's commitment to addressing climate change and its harmonization with the U.S. policies indicate the direction in which the federal government wants to move.

The Canadian federal government has actively sought to align its clean energy and climate change policies with those of the U.S. government. On January 30, 2010, Canada set a new goal to reduce GHG emissions in this country by 17 per cent below the 2005 level by 2020. This new target is a slight change from its earlier goal of reducing GHG emissions by 20 per cent below 2006 levels by 2020, which aligned with the U.S. targets[35].

In addition to setting GHG emissions reduction targets similar to those of the U.S., the Canadian government addresses GHG emissions within the transportation sector on a "continental basis" with the U.S. given that "we occupy the same economic space, the same environmental space, and the same energy marketplace"[36]. The government of Canada has announced its intention to take action on each of the major sources of GHG emissions starting with the transportation sector, the biggest source of GHG emissions in the country, accounting for 25% of Canada's total GHG emissions[37]. For the transportation sector, the Canadian government has put in place mandatory national emissions standards, referred to as *Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations* under the *Canadian Environmental Protection Act.* These standards are similar to U.S. regulations, effective 2011, requiring that new passenger cars and trucks must be fuel efficient and should produce lower GHG emissions. Furthermore, NRCan has initiated public consultation and formed a roundtable to develop of a roadmap for natural gas use in the transportation sector[38]. As a result, natural gas and electricity will likely play a bigger role in providing energy for transportation in the future.

---

[35] Climate change policy and GHG reduction targets are currently fragmented between federal and provincial levels. Government of Canada. "Canada's Action on Climate Change". May 6, 2010. Retrieved from http://www.climatechange.gc.ca/default.asp?lang=En&n=72F16A84-1

[36] National Post. "Canada Lowers Climate Change Target: Critics". January 30, 2010. Retrieved from http://www.nationalpost.com/news/story.html?id=2505931

[37] Environment Canada. "Government of Canada to Reduce Greenhouse Gas Emissions from Vehicles". April 1, 2009. Retrieved from: http://www.ec.gc.ca/default.asp?lang=En&n=714D9AAE-1&news=29FDD9F6-489A-4C5C-9115-193686D1C2B5

[38] Natural Resources Canada. "Public Consultation Activities". Retrieved from http://www.nrcan-rncan.gc.ca/com/consultation/concon-eng.php

In order to achieve its GHG emissions reduction targets, Canada is continuously developing policies that regulate emissions[39], enhance energy efficiency, and increase the share of renewable energy in the overall energy mix[40]. However, the federal government faces a significant challenge since domestic oil and natural gas production are contributors of economic benefits to Canada. The question becomes how does Canada reduce GHG emissions while maintaining the economic benefits that are generated from these resources? Although there has been a lack of leadership on developing a comprehensive federal plan to reduce GHG emissions, some provinces have been active in moving forward with their own plans and policies. Over time, this could lead to set of overlapping and potentially contradicting policies across Canada and the region as the Federal government evolves its energy and GHG policies forward.

2.2.1.2 United States

In recent years, the U.S. government has proposed aggressive energy policy reform, including the need for a reduction of GHG emissions (using a cap and trade program), which would encourage more clean renewable, sustainable energy development. On January 29, 2010, the U.S. federal government announced that it will reduce its own GHG emissions by 28 percent by 2020 and GHG emission reductions can be achieved by measuring current energy and fuel use, being more energy efficient and moving to clean energy sources such as solar, wind and geothermal [41]. The U.S. government and the Obama administration are also looking to the "green economy", in particular green energy, with more attention to the development of clean and renewable energy, to stimulate the economy, build local market capacity, foster innovation in clean energy industries, and increase jobs[42].

The U.S. is also focused on energy self sufficiency and energy independence in order to reduce its imported energy supply, increase domestic energy supply, and use of natural gas in sectors such as transportation or electricity generation to reduce the impact of GHG emissions and dependency on imported oil, and improve its energy security[43]:

- On May 15, 2009, the *American Clean Energy and Security Act* (the "ACESA") was introduced in the U.S. by U.S. House Energy and Commerce Committee Chairman

---

[39] In June 2010, Government of Canada announced its intent to regulate emissions from electricity sector, noting that thirteen per cent of Canada's total GHG emissions come from coal-fired electricity generation.

[40] Government of Canada. "Canada's Action on Climate Change". February 1, 2010. Retrieved from http://www.climatechange.gc.ca/default.asp?lang=En&n=D43918F1-1

[41] The White House Office of the Press Secretary. "President Obama Sets Greenhouse Gas Emissions Reduction Target for Federal Operations". January 29, 2010. Retrieved from http://www.whitehouse.gov/the-press-office/president-obama-sets-greenhouse-gas-emissions-reduction-target-federal-operations.

[42] The White House. "Energy & Environment". Retrieved from http://www.whitehouse.gov/issues/energy-and-environment

[43] The White House Office of the Press Secretary. "Remarks by the President on the Economy at Carnegie Mellon University". June 2, 2010. Retrieved from http://www.whitehouse.gov/the-press-office/remarks-president-economy-carnegie-mellon-university

Henry Waxman and House Energy and Environment Subcommittee Chairman Edward Markey (hence also referred to as the Waxman-Markey bill). The *ACESA* is a comprehensive national climate and energy bill aimed to establish an economy-wide, GHG cap-and-trade system to help address climate change and build a clean energy economy.

- On July 8, 2009 ,the *New Advanced Transportation to Give Americans Solutions Act* (the "NAT GAS Act") was introduced in the U.S. Senate by Senator Robert Menendez and co-sponsored U.S. Senate Majority Leader Harry Reid and Senator Orrin Hatch, which aims to extend and increase tax credits for NGV's and refueling. The NAT GAS Act will provide incentives for consumers, commercial truckers, and state and local governments to aggressively move from using vehicles burning polluting, imported gasoline and diesel, to vehicles running on clean, domestic natural gas.[44]

- On May 12, 2010, Senators John Kerry and Joe Lieberman introduced the *American Power Act* (the Kerry-Lieberman bill) to the Senate of the U.S., which has been deemed to reduce GHG emissions, provide incentives for the domestic production of clean energy technology, reduce dependence on foreign oil, create clean energy jobs, and secure the energy future of the U.S.[45] The new bill promotes domestic clean energy development, renewable energy and energy efficiency, clean transportation, and the capture and sequestration of carbons. This bill includes specific incentives for the conversion to clean, natural gas vehicles. The *American Power Act* is a further testament to the fact that GHG emissions reductions cannot be achieved without economic sustainability.

These bills are currently being reviewed by the Senate in the U.S. Congress and it is not clear which one, or if either, will be signed into law.

Both Canada and U.S. are increasingly focused on reducing GHG emissions and both countries are moving forward to a low carbon economy, promoting the development of alternative and renewable energy; however, there are distinct regional characteristics in both Canada and the U.S. that identify different energy requirements and solutions to meet their GHG emissions reduction objectives. For example, there are different challenges for reducing GHG emissions in provinces and states that have fossil fuel production driving their economy. This is further complicated by the changing mix in electricity generation fuels between jurisdictions. More specifically, some jurisdictions have much higher carbon intensity in these sectors than other jurisdictions. The regional context for B.C. is discussed next.

---

[44] NGV Global News. "New US NAT GAS Act of 2009 Introduced on 'Energy Independence Day'". July 8, 2009. Retrieved from http://www.ngvglobal.com/new-us-nat-gas-act-of-2009-introduced-on-energy-independence-day-0708

[45] The *American Power Act*. Retrieved from http://kerry.senate.gov/work/issues/issue/?id=7f6b4d4a-da4a-409e-a5e7-15567cc9e95c

2.2.2 PACIFIC NORTHWEST REGIONAL CONTEXT

Although GHG emission reductions cannot be addressed solely within the boundaries of any single political jurisdiction, GHG emission sources can be unique to each jurisdiction and therefore policies, regulations, initiatives, and solutions to reduce GHG emissions may be different based on how such emissions are produced in each jurisdiction.

The PNW refers most commonly to three northwestern states in the U.S. (Washington, Oregon, Idaho) and B.C. in Canada[46]. With the exception of B.C., where electricity supply is predominantly from hydroelectric generation, and currently over 90 per cent of electricity generation is renewable low or no carbon electricity[47], political leaders and utilities in the PNW region, generally consider natural gas to be a solution to their climate change goals both in electricity generation and direct use applications[48]. This is mainly due to the fact that the greatest source of GHG emissions for northwest U.S. comes from coal-fired electricity generation and so policies are developed to move away from coal-based electricity generation to natural gas or renewables combined with natural gas in order to significantly reduce GHG emissions output in this sector[49]. In B.C., however, electricity supply is predominantly from hydroelectric generation, with currently over 90 per cent of generation from renewable low or no carbon electricity[50], resulting in the development of policies that are unique among PNW jurisdictions with regard to the role of natural gas and electricity in meeting energy demands from customers and businesses.

Since using natural gas for space heating and other appliances in the home is more efficient than using natural gas to generate electricity (the marginal resource in the PNW)[51] for use in these same applications, direct use of natural gas is the preferred choice for both the customer and the utility, over electricity. Lower GHG emissions and downward pressure on overall energy costs contribute to the case for direct use of natural gas where it can be used at high efficiencies. For example, utilities such as Puget Sound Energy ("PSE") and Avista Utilities, both combined electric and natural gas utilities, promote the direct use of natural gas as away to avoid new electricity demand, even in service territories where another utility provides the natural gas, and thus realizes the increased demand from such programs. Further, these jurisdictions see that natural gas generation has a role to play in firming intermittent renewable electricity generation. These utilities see natural gas as an important solution to the region's

46 In some contexts, references to the Pacific Northwest can also include the State of Montana, the Province of Alberta and occasionally the State of Alaska.
47 British Columbia Ministry of Energy, Mines and Petroleum Resources. "Electric Generation and Supply". Retrieved from http://www.empr.gov.bc.ca/EPD/Electricity/supply/Pages/default.aspx
48 Direct use of natural gas in home heating, water heating, cooking, and clothes drying.
49 Discussion Paper – Energy Planning and Climate Change Issues in the Pacific Northwest Region. Included in the Terasen Gas 2008 Resource Plan, Appendix B: Regional Policy Issues.
50 British Columbia Ministry of Energy, Mines and Petroleum Resources. "Electric Generation and Supply". Retrieved from http://www.empr.gov.bc.ca/EPD/Electricity/supply/Pages/default.aspx
51 Northwest Power and Conservation Council. February 2010. 6th Northwest Power Plan, Appendix D, page D-2.

climate change challenges and for reducing their own GHG emissions or meeting state-mandated renewable portfolio standards, while still managing cost impacts for customers[52].

For example, PSE, which serves the Puget Sound region of the northwest U.S., recommends using natural gas directly for home space and water heating when available and encourages customers to switch their heating from electricity to natural gas. Some of the customer benefits that PSE indicates with a conversion to natural gas are lower energy costs, environmental benefits, higher efficiencies and lower cost to maintain natural gas furnaces, increased home value, and versatility[53].

The NWGA advocates climate change policies, promoting the right energy source for the right use. "For instance, high-efficiency end-use natural gas applications such as residential furnaces, tank and instantaneous tankless water heaters, commercial boilers, industrial furnaces and combined heat and power systems are all applications where natural gas is more energy efficient than equivalent electric systems"[54].

The NPCC currently uses the following policy in promoting the direct use of natural gas for space and water heating in the region:

> *The Council recognizes that there are applications in which it is more energy efficient to use natural gas directly than to generate electricity from natural gas and then use the electricity in the end-use application. The Council also recognizes that in many cases the direct use of natural gas can be more economically efficient. These potentially cost-effective reductions in electricity use, while not defined as conservation in the sense the Council uses the term, are nevertheless alternatives to be considered in planning for future electricity requirements.*
>
> *The changing nature of energy markets, the substantial benefits that can accrue from healthy competition among natural gas, electricity, and other fuels, and the desire to preserve individual energy source choices all support the Council taking a market-oriented approach to encouraging efficient fuel decisions in the region*[55].
>
> *Furthermore, natural gas is viewed as a pillar of the region's electricity resource strategy to reduce the use of coal fired generation and allows the integration of a growing fleet of*

---

[52] Electric power generation is from different sources, coal-fired power plants (36%), hydroelectric (41%), natural gas (20%) and the remaining sources include nuclear, biomass, landfill gas, petroleum, waste and wind. Puget Sound Energy. "Energy Supply: Electricity- Power Supply Profile". Retrieved from http://www.pse.com/energyEnvironment/energysupply/Pages/EnergySupply-Electricity-PowerSupplyProfile.aspx

[53] Puget Sound Energy. "Choosing Natural Gas". Retrieved from http://www.pse.com/solutions/foryourhome/pages/ChoosingNatGas.aspx?tab=1&chapter=1

[54] NWGA. "Natural Gas and Climate Change in the Pacific Northwest", p. 3. See Appendix A-2.

[55] Northwest Power and Conservation Council. Sixth Northwest Conservation and Electric Power Plan. February 2010. Page 8-2. http://www.nwcouncil.org/energy/powerplan/6/Default.htm

intermittent renewable resources[56]. In most jurisdictions in the PNW, new large hydro projects are not permitted due to their impact on the environment' eliminating the potential development of such resources to accompany the intermittency of renewables.

The use of natural gas as a transportation fuel alternative to gasoline and diesel, using Compressed Natural Gas ("CNG") or Liquefied Natural Gas ("LNG"), is being explored in the PNW region, where it is a low-cost, low-emissions fuel used for passenger vehicles, buses, delivery vans, taxis, postal vehicles, ferries, port applications, and so forth[57].

Thus, natural gas plays an important role in reducing GHG emissions in Washington, Oregon and Idaho, reducing demands on foreign petroleum, and diversity of transportation fuel in the PNW region. Given that these jurisdictions can use natural gas in direct use application and to produce electricity to reduce their GHG emissions, they do not have the pressing need to utilize natural gas in combination with geothermal or solar in order to reduce the carbon intensity of the energy consumed in thermal applications. Instead, more emphasis has been placed on the role of alternative energy, such as wind for electric generation in the Pacific Northwest.

2.2.2.1 Pacific Northwest: Summary

Given that the PNW views natural gas as a critical component for reducing GHG emissions, along with increased efficiency, adding renewable generation resources and improving infrastructure[58] there is an anticipated increase in regional demand for natural gas. Pricing of carbon will inevitably result in an increase in gas fired generators and thus most of the increase in demand for natural gas[59]. The PNW region needs to retain and secure access to abundant and diverse sources of supply and must ensure associated transmission, storage, and distribution infrastructure can grow as necessary[60]. Since B.C. is part of the PNW region, the anticipated increase in demand of natural gas within the region will provide B.C. an opportunity to leverage its new natural gas supply resources to fulfill this anticipated market demand.

2.2.3 B.C. PROVINCIAL GOVERNMENT AND MUNICIPALITIES

The B.C. provincial government along with many municipalities within the province, are all aggressively encouraging the reduction of GHG emissions, by having a focus on lowering energy consumption and improving energy efficiency and conservation, and are keen in their search for and developing of alternative (and renewable) energy sources.

---

56 Northwest Power and Conservation Council. Sixth Northwest Conservation and Electric Power Plan. February 2010. Page 10-2.
57 NWGA. "Natural Gas and Climate Change in the Pacific Northwest". See Appendix A-2.
58 Northwest Power and Conservation Council. February 2010. "Sixth Northwest Conservation and Electric Power Plan". Ch 10, p. 1&2.
59 CERI presentation. Climate Change & Natural Gas. April 2010. Presented by David C. McColl.
60 NWGA. "Natural Gas and Climate Change in the Pacific Northwest". See Appendix A-2.

The role of natural gas and electricity is the energy mix is different in B.C. compared to other jurisdictions in the PNW due to the fact that B.C.'s electricity supply is predominantly from hydroelectric generation, with over 90 per cent of generation currently from renewable low or no carbon electricity[61]. The B.C. government has been an active leader in clean energy policies and initiatives, encouraging the switch from higher to lower emission energy sources. However, as a GHG emitting energy source natural gas for home heating and other direct use applications is facing challenges in B.C.'s policy environment given that the electricity produced in the Province is viewed as clean and renewable. Also, there is less emphasis placed on use of natural gas for electricity generation in B.C., as opposed to other regions in the PNW, due to the large capability of the heritage assets within BC Hydro supply resources and also the considerable potential for renewable resource development in the Province. This preference of the electricity use over natural gas influences public perception regarding energy production and consumption, particularly in the role that natural gas can play as part of the solution in climate change initiatives.

If implementation of B.C. government policies was to result in substantial electrification in sectors currently served by gas, the Province would face substantial electricity supply and capacity concerns in the future. Given this reality, alternative energy solutions will likely play a bigger role in the future supported by natural gas. As more and more energy and climate change policies are implemented and refined, government, utilities, and stakeholders must continue their efforts to make sure public policy is clear and understood by all so that solutions can be found to achieve the established goals.

The implications of these policies for utilities are profound, and utilities are compelled to respond. Given these external realities, the Terasen Utilities have introduced new service offerings to augment the Utilities' natural gas business as a response to the challenges and opportunities presented by climate change policies. These new service offerings include alternative energy solutions, such as geothermal, solar and district energy systems. A summary of the key B.C. government legislative developments are discussed below.

2.2.3.1 Clean Energy Act

On April 28, 2010, the B.C. government announced the CEA (Bill 17), which aims to ensure electricity self-sufficiency at low electricity rates by 2016, to harness B.C.'s clean power potential to create jobs, and to strengthen environmental stewardship and reduce GHG emissions. It focuses almost exclusively on electricity, and sets conditions for the development of an electricity export market. A copy of the CEA is provided in Appendix A-1. Section 2 sets out B.C.'s new energy objectives,[62] almost all of these objectives have implications for energy

---

[61] British Columbia Ministry of Energy, Mines and Petroleum Resources. "Electric Generation and Supply". Retrieved from http://www.empr.gov.bc.ca/EPD/Electricity/supply/Pages/default.aspx

[62] Some of these objectives build on existing policies and previously publicized objectives, such as those contained in the 2007 BC Energy Policy.

efficiency and optimization, and carbon reduction solutions that the Terasen Utilities can provide as part of its vision and action plan for the future.

The *CEA* focuses on the ideals of electricity self sufficiency within the Province and becoming a net electricity exporter. Two significant actions that cement the Province's strategy for achieving these conditions are dictated by the CEA: BC Hydro and BCTC are to be recombined and a significant reduction in the BCUC oversight of BC Hydro and BCTC will be implemented. Approval of over $10 billion in new capital projects (such as Site C and the Smart Metering initiative) will thus be outside the BCUC's purview. In addition, BC Hydro no longer has to file long term resource plans with the BCUC, but rather the recombined BC Hydro must fine an integrated resource plan with the government. The *CEA* mandates conservation targets for BC Hydro, whereby BC Hydro must acquire 66% of load growth to 2020 through demand side measures, up from 50% previously specified and requires (subject to ministerial regulation) that smart meters are installed at all BC Hydro customer premises by the end of 2012.

The *CEA* encourages the use of natural gas, electricity, and hydrogen for vehicles as alternatives to high GHG emitting fuels like gasoline and diesel. It is also supportive of alternative energy and biogas. The *Clean Energy Act's* new definition for "demand side measure" excludes electricity-to-gas fuel switching as an option, which could likely change customer's and public's perception of natural gas as a clean and efficient fuel to be encouraged. While this act does not promote the use of natural gas over electricity for thermal uses; neither does it preclude the use of natural gas over electricity, recognizing the important role that both energy types play in meeting B.C.'s energy and resource needs. With the current focus by the provincial government and media placed on electricity in B.C. being a renewable energy source there may be confusion about the role of natural gas among customers and stakeholders.

The *CEA* seeks to address a number of impediments in the existing legislative and regulatory framework to achieving the Province's goal of becoming a green energy powerhouse. However, much of what is expressed in the *CEA* is an extension of previously stated or referenced government priorities, many of which are discussed through the remainder of this section. The *CEA* also leaves open quite a number of areas for future determination through the issuance of regulations by the Minister or the Lieutenant Governor in Council.

2.2.3.2 Energy Plan 2007: A Vision for Clean Energy Leadership

On February 27, 2007, the B.C. government released a new Energy Plan: A Vision for Clean Energy Leadership, which continues to build on the policies that were outlines in the Energy Plan of 2002. The introduction of the Energy Plan in 2007 marked a significant change in the energy policy landscape in B.C. whereby the government demonstrated its commitment to the production of clean energy and reduction of GHG emissions in the province, by leveraging the province's key natural strengths and competitive advantages involving clean and renewable sources of energy. The Energy Plan of 2007 has the following goals and objectives:

a) Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.

b) Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.

c) Encourage utilities to pursue cost effective and competitive demand side management opportunities.

d) Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.

e) Implement Energy Efficiency Standards for Buildings by 2010.

f) All new electricity generating facilities constructed in British Columbia will have net zero greenhouse gas emissions.

g) By 2016, existing thermal generating power plants will achieve zero net greenhouse gas emissions.

h) Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.

i) Ensure self-sufficiency to meet electricity needs by 2016, plus "insurance" power to supply unexpected demand thereafter

j) New provincial public sector buildings will be required to integrate environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.

k) Increase participation in the Community Action on Energy Efficiency program and expand the First Nations and Remote Community Clean Energy program.

Furthermore, in the Energy Plan, the government indicates its commitment to reducing GHG emissions from the transportation sector. The transportation sector is the largest source of GHG emissions in the province accounting for approximately 39% of the Province's emissions. Diesel and gasoline are the primary fuels used in the transportation sector and as such account for a significant portion of the GHG emissions as well as contribute to a reduction in air-quality in Metro Vancouver. Vehicle retrofit technology is available to convert vehicles to cleaner fuel sources. The Energy Plan highlights that "natural gas burns cleaner than either gasoline or propane, resulting in less air pollution,[63]" implying that the adoption of NGVs can play a role in helping the province reduce GHG emissions in the transportation sector.

[63] 2007 BC Energy Plan – A Vision for Clean Energy Leadership, p. 19

The Energy Plan for 2007 sets ambitious targets and also sets out a strategy for reducing the province's GHG emissions and a commitment to unprecedented investments in alternative energy technology.

2.2.3.3 Greenhouse Gas Reduction Targets Act and Offset Emissions Regulation

As part of the B.C. Throne Speech delivered on February 13, 2007, the government first announced targets for provincial GHG reductions. Effective January 1, 2008, the *Greenhouse Gas Reductions Targets Act* enshrines in law the provincial government's commitment to becoming carbon neutral, and sets province wide targets for GHG emissions reductions of:

- 33% from the 2007 level by 2020, and
- 80% from the 2007 level by 2050

On November 25, 2008, further GHG interim targets were set by Ministerial Order to:

- 6% below 2007 levels by 2012, and
- 16% below the 2007 levels by 2016

The *Greenhouse Gas Reductions Targets Act* made B.C. the first jurisdiction in North America to make a legally binding commitment to carbon neutral operations.

The Pacific Carbon Trust, acting on behalf of the Province of B.C., acquires GHG offsets from projects that are located in B.C. and that meet provincial eligibility criteria as defined by the Offset Emissions Regulation. The Emission Offsets Regulation received royal assent on December 3, 2008, under the provisions of the *Greenhouse Gas Reduction Targets Act.* The emission offsets regulation sets out requirements for GHG reductions and removals from projects or actions to be recognized as emission offsets for the purposes of fulfilling the provincial government's commitment to a carbon-neutral public sector. Offsets represent emission reductions or removals through projects such as renewable energy generation and energy efficiency initiatives.

2.2.3.4 Carbon Tax Act

In July 2008, B.C. government became the first jurisdiction in North America to introduce a consumer–based carbon tax. Through the use of price signals the carbon tax is intended to encourage consumers to reduce their use of fossil fuels and related emissions, thus influencing individuals and businesses to make more environmentally responsible choices. The *Carbon Tax Act* was introduced as creating a revenue-neutral carbon tax, and requiring the Minister of Finance to return carbon tax revenues to taxpayers through income tax cuts. The carbon tax is intended to apply to the retail purchase or use in B.C. of fossil fuels, including gasoline, diesel fuel, natural gas, home heating fuel, propane and coal. The initial tax rate was based on $10 per tonne of carbon dioxide-equivalent emissions released from burning the fuel, with increases by $5 per tonne over the following four years reaching $30 per tonne as of July 1, 2012. This Act added $0.50 per gigajoule ("GJ") to the cost of natural gas in the first year, rising to $1.50/GJ after 4 years from the date of implementation. It is projected that the tax will generate revenues of about $1.85 billion over the first three years. The carbon tax gives consumers in B.C. a choice on how they wish to adapt their behaviour to reduce their consumption of fossil fuels and is expected to help the government of B.C. achieve about 7.5 per cent of the government's legislated GHG emissions reductions by 2020.

Potential for carbon tax increases and the level of tax beyond 2012 remain uncertain at the present time. However, in its report entitled "Meeting British Columbia's Targets: A report from the B.C. Climate Action Team", the Climate Action Team recommends the following:

> *"After 2012, if required to achieve the emissions targets, increase the British Columbia carbon tax in a manner that aligns with the policies of other jurisdictions and key economic facts"*[64].

There are some reports that indicate carbon taxes may need to go up to $300 per tonne in order to have a meaningful impact on consumer behavior and therefore reduce GHG emissions[65].

2.2.3.5 2008 Amendments to the Utilities Commission Act and DSM Regulation

In 2008, the B.C. government enacted amendments to the Act to reflect the following "government's energy objectives":

- to encourage public utilities to reduce greenhouse gas emissions;
- to encourage public utilities to take demand-side measures;
- to encourage public utilities to produce, generate and acquire electricity from clean or renewable sources;
- to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility;
- to encourage public utilities to use innovative energy technologies; and

64 Meeting British Columbia's Targets, A Report from the B.C. Climate Action Team, July 28, 2008, page 3

65 J & C Nyboer and Associates, Inc. A Technology Roadmap to Low Greenhouse Gas Emissions in the Canadian Economy: A sectoral and regional analysis, dated August 22, 2008, prepared for National Round Table on the Environment and the Economy.

- to encourage public utilities to take prescribed actions in support of any other goals prescribed by regulation.

The Commission is required to consider government's energy objectives in the context of long-term plans, applications for a CPCN, applications for approval of expenditure schedules and energy purchase contracts.

A further regulation that is administered by the BCUC is the Demand-Side Measures Regulation. These regulations were approved by Order-in-Council No. M271/2008 on November 6, 2008. Key changes introduced by the regulation are:

1. A public utility's DSM plan portfolio is adequate for the purposes of the Act only if the plan portfolio includes all of the following:
    - A demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;
    - If the plan portfolio is submitted on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations.
    - An education program for students enrolled in schools in the public utility's service area
    - If the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area
2. The Commission considers a number of items in cost effectiveness of a public utility's DSM plan portfolio, including:
    - Cost effectiveness of a DSM proposed in an expenditure portfolio or a plan portfolio may compare the costs and benefits of the DSM individually, the DSM and other DSMs in the portfolio, of the portfolio as a whole.
    - The Total Resource Cost ("TRC") test must be used in determining cost effectiveness of DSM for low income households and in using the TRC test, the benefit of DSM to be 130% of its value.
    - Cost effectiveness of a specified DSM proposed in a plan portfolio or an expenditure portfolio must be determined by cost effectiveness of the portfolio as a whole.
    - Cost effectiveness of a public awareness program must be determined by the cost effectiveness of the DSM portfolio as a whole.

- The Ratepayer Impact Measure ("RIM") test cannot be used as basis for finding a program not to be cost-effective.

TGI and TGVI have been involved in EEC activities for some time and these programs have been successful in the past in promoting the efficient use of natural gas, encouraging the adoption of low carbon energy alternatives, reducing energy costs for customers, and supporting government policy by reducing GHG emissions. TGI and TGVI will continue to explore new area's of opportunity within this field as we have done recently with the 2008 EEC Application, which secured increased funding for EEC activities and programs, allowing for a broader set of programs to be rolled out to customers.

2.2.3.6 B.C. Climate Action Charter and Municipal Government Commitments

Under the *Greenhouse Gas Reduction Targets Act*, the B.C. government has made a legally binding commitment to become carbon neutral by 2012. Not only has the province of B.C. shown leadership in establishing challenging energy and climate change objectives, local governments from across B.C. have joined with the Province and the Union of B.C. Municipalities by committing to the British Columbia Climate Action Charter pledging to significantly cut GHG emissions by 2012 through carbon neutrality. Carbon neutrality will mean having no net emissions of GHGs, generally achieved through reducing GHG emissions where possible, by investing in projects that eliminate GHGs, and capturing and containing GHG emissions. As of January 20, 2010 - 177 local governments and the Islands Trust have now signed the Charter and these signatories commit to carbon neutrality in internal operations by 2012, measuring and reporting on community GHG emissions profile, and creating complete, compact, more energy efficient communities.

As a result of new policies and efforts to address global warming, municipalities are being compelled to reduce their carbon footprint and this sector's actions will further impact B.C.'s efforts in becoming a low carbon economy. However, there is a cost to these municipalities for reducing their carbon footprint and a lack of clarity as to what carbon neutrality means. In the absence of specific guidance as to how they should interpret it, many municipalities are facing struggles in achieving what they have signed up for. For example, the municipalities around Trail have committed to have their operations carbon-neutral by 2012, either by doing things internally or by purchasing offsets. However, there are outstanding questions about how this will be achieved, such as whether the city must also consider emissions by its contractors[66]. Furthermore, there are discrepancies between what the federal and provincial governments consider as carbon sequestering, including whether planting a tree counts towards reducing GHG emissions.

---

[66] Trail Daily Times, "Carbon plans moving slowly". May 19, 2010. Retrieved from http://www.trailtimes.ca/article/20100519/TRAIL0101/305199958/carbon-plans-moving-slowly

The two largest municipalities in B.C. — Vancouver and Surrey — are examined to see how they are achieving carbon neutrality and their long term goals on reducing carbon footprint.

- **City of Vancouver: Green Capital**

The City of Vancouver has an action plan for becoming the world's greenest city by 2020. In order to progress toward an environmentally sustainable future, the City of Vancouver is developing plans—for the green economy, energy-efficient buildings, clean transportation, urban forest management, and so forth. The City's goal is to position Vancouver as a Green Capital – a hotbed of green commerce and innovation. The action plan focuses on three areas: 1) green economy and green jobs, 2) greener communities, and 3) human health. The following are the goals set in the City's action plan related to the green economy, green jobs, and greener communities:

1. Green Economy Capital: Secure Vancouver's international reputation as a mecca of green enterprise
    - 2020 Target: Create 20,000 new green jobs
2. Climate Leadership: Eliminate Vancouver's dependence on fossil fuels
    - 2020 Target: Reduce greenhouse gas emissions 33 per cent from 2007 levels
3. Green Buildings: Lead the world in green building design and construction
    - 2020 Targets: All new construction carbon neutral; improve efficiency of existing buildings by 20 per cent
4. Green Mobility: Make walking, cycling, and public transit preferred transportation options
    - 2020 Target: Make the majority of trips (over 50 per cent) on foot, bicycle, and public transit
5. Zero Waste: Create zero waste
    - 2020 Target: Reduce solid waste per capita going to landfill or incinerator by 40 per cent
6. Easy Access To Nature: Provide incomparable access to green spaces, including the world's most spectacular urban forest
    - 2020 Targets: Every person lives within a five-minute walk of a park, beach, greenway, or other natural space; plant 150,000 additional trees in the city

7. Lighter Footprint: Achieve a one-planet ecological footprint

    - 2020 Target: Reduce per capita ecological footprint by 33 per cent

The City of Vancouver's general strategy to achieve carbon neutrality from its own operations is to use best practices to reduce emissions from civic buildings, fleet, and solid waste and to offset remaining emissions by developing incremental, verifiable GHG reduction projects and programs in the local community.

The City of Vancouver is taking actions to become the greenest city by 2020. In following Vancouver's lead as the world's new Green Capital, other municipalities in British Columbia and elsewhere will adopt similar initiatives following in Vancouver's footsteps and leverage on opportunities that the City of Vancouver creates.

- **City of Surrey: Advancing Sustainability**

The City of Surrey, as one of the fastest growing municipalities in B.C., continues to work on becoming a greener and more sustainable city, positioning itself as a premier investment location and leader in the sustainability sector, specifically by becoming an appealing location choice for clean technology companies.

Surrey's Sustainability Charter is the first document of its kind in the Lower Mainland and is designed to guide the City's approach to social, cultural, environmental and economic sustainability.

The Sustainability Charter outlines specific goals for achieving the vision for and commitment to sustainability. As part of its sustainability initiatives, the city of "Surrey incorporates "Triple Bottom Line Accounting" into its operations, incorporates and encourages alternative energy sources, and strives for carbon neutrality and no net impact from waste". The City will seek ways to reduce the use of fossil fuels and to be carbon neutral, through a wide range of alternative energy sources that focus on renewable energy. These may include district heating systems, wind, active and passive solar, biomass, waste to energy and geo-exchange heating and cooling. Most resources will be produced locally, recycled or reused.

The increasing efforts of various municipalities to achieve carbon neutrality and to meet long term goals on reducing carbon footprint indicate that customers expectations on way of life are changing and thus companies, such as the Terasen Utilities, play an important role in bringing out the best practices and offering low carbon solutions and services for customers to meet the climate change objectives.

2.2.3.7 B.C. Bioenergy Strategy

On January 31, 2009, the B.C. Bioenergy Strategy was released by the Province (see Appendix A-3 for a copy of this strategy). In this document, the Province is focused on developing bioenergy resources in B.C. to enhance both the environmental and economic benefits for the people who live in B.C.[67] Bioenergy includes waste from landfills, water treatment plants and agriculture. TGI is moving forward in making these goals a reality with our recent biomethane application, which was filed with the BCUC on June 8, 2010. See Sections 3 and 6 for more details on this application.

2.2.3.8 B.C. Speech from the Throne (2010)

The February 10, 2010, B.C. Speech from the Throne re-emphasized clean energy as a cornerstone of B.C.'s Climate Action Plan to reduce GHG emissions[68]. It also highlighted that the government is pursuing clean modes of transportation, such as using vehicles powered by CNG and LNG.

2.2.3.9 B.C. Provincial Government and Municipalities: Summary

Public policies and government initiatives in B.C. have focused on encouraging clean energy to a large extend in response to the achieve GHG emissions reduction goals. These policies and initiatives emphasize lowering energy consumption and improving energy efficiency and conservation, and are keen in their search for and developing of alternative (and renewable) energy sources. However, the policy environment in B.C. could be interpreted by some stakeholders or customer s to favor the use of electricity over natural gas, a low carbon energy source that can be used in direct use application, electricity generation, and transportation sector. As more and more energy and climate change policies are implemented and refined, government, utilities, and stakeholders must continue their efforts to make sure public policy is clear and understood by all so that solutions can be found to achieve the established goals.

2.2.4 ENERGY AND CLIMATE CHANGE POLICY AND LEGISLATION: SUMMARY

Energy policy at all levels of government is increasingly focused on addressing climate change and the reduction of GHG emissions. Given that the climate is a concern across all jurisdictions and the energy sector has broader social, economic, and environmental impacts, which go beyond political boundaries within the region, energy planning and policies should be considered within a North American regional context.

Natural gas is expected to "act as the transition fuel towards a low carbon economy"[69] in North America and has an important role in long-term sustainability due to the advantages inherent in

---

[67] BC Bioenergy Strategy: Growing Our Natural Energy Advantage, page 5. See Appendix A-3.
[68] Legislative Assembly of British Columbia. Speech from the Throne. February 9, 2010. Retrieved from http://www.leg.bc.ca/39th2nd/4-8-39-2.htm
[69] CERI presentation. Climate Change & Natural Gas. April 2010. Presented by David C. McColl.

its physical properties (i.e. lowest emissions of the fossil fuels, no/low particulate matter, etc.)[70]. Elsewhere in North America, where energy needs are frequently met through burning coal or refined petroleum products, natural gas is recognized as a cleanest fossil fuel and consumers are encouraged to use gas in place of electricity. In B.C., by contrast, there is an abundance of renewable sources of hydro-electric generation. We must overcome the perception that electricity is always the right energy source, and that natural gas should be displaced by electricity for traditional applications such as space and water heating and other direct use applications. Natural gas is also complementary to many of the renewable and alternative energy sources, such as geothermal and solar, that provide carbon intensity-reducing solutions for energy consumption. There are more sustainable solutions than using electricity alone, which result in lower net emissions and reduced energy use. These will be achieved by continuously seeking to employ each energy form in its highest and best uses across interconnected energy grids regardless of jurisdictional borders.

Natural gas is a clean, efficient, and abundant source of energy that plays an important role in the energy portfolio, whether it is used for direct application, electricity generation, transportation, or as a supplementary source for renewable and alternative energy. Recognizing this, the Terasen Utilities continue to evolve its customer offerings and integrating natural gas in its energy solutions to customers. These solutions promote the efficient use of energy and help customers reduce their carbon intensity. First, we have secured expanded funding to provide further EEC programs to our customers. Second, we have secured approval from the BCUC and customers to undertake integrated energy solutions (such as geothermal, solar and other technologies), in combination with natural gas within the regulated entity of Terasen Utilities. This ultimately will lead to a broader set of energy solutions for customers. Third, on June 8, 2010, TGI filed with the BCUC an end to end business model for the development and sales of Biomethane to our customers. This application, if approved, will provide our customers with lower carbon solutions. Fourth, as discussed in Section 3, we are working towards transportation solutions to provide CNG and LNG to customers.

Given that natural gas is a fuel of choice for a low carbon economy that can be used efficiently in direct applications for thermal energy, electricity generation, transportation, and as an integral source in alternative energy applications, we expect to see a growing demand for it and will therefore require the necessary infrastructure and resources to meet the demand. When energy alternatives exist it is imperative that the appropriate rates and incentive mechanisms, as well as consistent messaging, are in place to encourage the efficient use of energy. In this way, carbon reduction may be enhanced through appropriate energy choice.

---

70 Natural gas is widely referred to as transition fuel as it is the lowest emitting fossil fuel and an abundant flexible source of energy to support the move to a low carbon economy, because it can be used in direct use applications, to produce electricity, and in the transportation sector. This flexibility helps to reduce GHG emissions in an economic way by displacing higher carbon fuels.

III. APPLICATION

A. External Situational Context

Over the next 20 years the province of B.C.'s population is expected to grow by more than 25 per cent or over 1 million people.[18] Demand for all types of energy is expected to increase – even as the pressure to improve energy conservation and efficiency measures intensifies. Terasen Gas is committed to being part of the solution in providing this energy. To do so, the Company must ensure its business evolves along with the world in which it operates.

The forecasted costs identified in this Application reflect our careful consideration of what steps are required to meet the changing needs of TGI customers, the communities the Company serves and its shareholder. They reflect consideration of external factors such as Terasen Gas' level of competitiveness, B.C.'s evolving provincial energy and environmental policies, changing economic realities and more. Overall, these developments present increasing challenges to the Company's natural gas business, but also present an opportunity for the provision of other energy solutions to our customers.

In this section of the Application we suggest there are five material external realities that must be considered when reviewing the requests made later in this Application. These external factors are:

1. **Energy policy at all levels of government is increasingly focused on addressing climate change and energy conservation, and TGI business must evolve to support this focus.** This section will explore how B.C. Government Policy, Municipal Government Policy, and Federal Government Policy are all aggressively encouraging the reduction of GHGs, have a focus on lowering energy consumption, and are keen in their search for and developing alternative (and renewable) energy sources. The implications of these policies for Terasen Gas are important and will be outlined in the Application.

2. **Expectations of Customers, Regulators, and Other Stakeholders are evolving, and Terasen Gas will have to take action to continue meeting their respective needs.** Within this section we discuss what customers expect from Terasen Gas related to customer care and meeting their energy needs. Customers' energy needs are changing with concerns about GHG emissions and energy efficiency, as such customers are looking at reducing consumption, finding alternative energy options and communities are becoming engaged in energy planning. This section will also discuss how the public

[18] See Appendix C-1 for a copy of BC Stats, BC Population Forecast

is increasingly concerned about public safety and security. These issues are addressed by looking at how regulators are mandating that Terasen Gas change to meet new codes and regulations.

3. **Terasen Gas' competitive position continues to decline relative to its peers and competitors.** In this section of the Application, Terasen Gas will outline how natural gas market prices have improved relative to other energy commodities (such as oil) in the North America marketplace, but faces challenges in the B.C. marketplace due to the differing nature of how natural gas and electricity costs are set into customer rates. This poses challenges, to which we must respond. This competitive challenge is not only an economic one, but is also related to customers' changing perceptions about how the use of natural gas contributes to climate change.

4. **BC Economic Outlook and Demographic Challenges.** In this section of the application Terasen Gas explores the economic outlook for B.C. in the coming years and the issue of changing demographics in the workforce. These topics have implications for Terasen Gas and its customers.

5. **Accounting standards and related guidance are in Flux.** Canadian accounting standards are now entering a time of unprecedented change. Canadian utilities will be required to comply with IFRS for financial reporting periods commencing on or after January 1, 2011, with comparative figures for 2010 restated to be in compliance with IFRS. This section discusses these recent changes and its future impact on setting delivery rates to Terasen Gas customers.

Together these external realities help to provide some context to Terasen Gas business opportunities and challenges in meeting its role as being a trusted energy provider to customers in the province of B.C. in the coming years. These topics are discussed in more detail below.

On May 15, 2009, the Terasen Utilities filed an ROE Application seeking to correct the ROE mechanism and, for Terasen Gas, seeking to increase the equity component of its capital structure, so as to provide Terasen Gas with an opportunity to earn a fair return on its investment. The ROE Application or any resulting impacts on the Company's revenue requirements and rate proposals is not discussed in this RRA. However, following a decision on the ROE Application, the proposed rates in this Application will have to be adjusted to reflect the results of the ROE Application decision. It should be recognized that the outcome of that proceeding affects the financial health of Terasen Gas. Ultimately, this has an impact on our customers.

1. Energy Policy at all Levels of Government is Increasingly Focused on Addressing Climate Change and Energy Conservation, and the Terasen Gas Business Must Evolve to Support this Focus

In recent years B.C.'s provincial government and municipalities have taken steps to develop targets and action plans to support the reduction in GHG emissions. The actions of Canada's federal government, while not (yet) reflected in formal policy, reinforce this focus on cutting GHG emissions while reducing consumption of carbon based fuels. With the recent changes in the federal government of the United States, there is a renewed commitment to clean energy and GHG reduction.[19] Thus, all levels of government across North America recognize that GHG reduction is a pressing reality.

Climate change and energy consumption are subjects of enormous importance to British Columbians today and into the future. The public has accepted that GHGs contribute to climate change and that action must be taken. TGI supports sustainability initiatives through its Energy and Efficiency Conservation programs and in its own operations. There is nevertheless an important role for natural gas in the long-term sustainability picture due to the advantages inherent in its physical properties, i.e. lowest emissions of the fossil fuels, no/low particulate matter, etc. Consumers also want clean air and affordable comfort, in addition to carbon reductions, all of which are areas where natural gas provides benefits. Natural gas will continue to be the right choice for the majority of consumers, and its use should be encouraged where it is the right energy form for the right application at the right time given its relative stage of commercial and technological development. Using natural gas in more applications can serve to reduce GHG emissions and more. When fuel alternatives exist it is imperative that the appropriate rates and incentive mechanisms, as well as consistent messaging, are in place to encourage the efficient use of energy through market-based approaches. In this way, carbon reduction may be enhanced through energy choice.

Elsewhere in North America, where energy needs are frequently met through burning coal or refined petroleum products, natural gas is recognized as a clean alternative. In British Columbia, by contrast, there is an abundance of renewable sources of hydro-electric generation. TGI must overcome the perception that hydroelectricity is always the right energy source, and that natural gas should be displaced by electricity for traditional applications such as space and water heating and other direct use applications. There are better solutions than using electricity alone which result in lower net emissions

[19] On May 15, 2009 U.S. House Energy and Commerce Committee Chairman Henry Waxman and House Energy and Environment Subcommittee Chairman Edward Markey introduced H.R. 2454, The American Clean Energy and Security Act ("ACESA"), which calls for an economy-wide GHG cap and trade system and other complementary GHG reduction measures.

and reduced energy use by continuously seeking to use each energy form to its highest and best value across interconnected energy grids regardless of geographic borders.

Terasen Gas is committed to being part of the solution by ensuring customers have access to the energy they need while also promoting Energy Efficiency and Conservation. Terasen Gas also recognizes that these laudable objectives and goals represent challenges to the Company's traditional natural gas business. It is thus important for Terasen Gas to undertake and explore new initiatives that support government policy while at the same time helping our customers find energy solutions that meet their changing needs. In fact, energy policy calls upon utilities to play an integral role in doing this very thing.[20] There are opportunities for the use of other non-traditional energy sources, both in conjunction with natural gas and on their own. There are opportunities for TGI to be a provider of energy solutions beyond just gas. Indeed, TGI considers it to be vital that we become a provider of diverse energy solutions for customers. The steps TGI is taking to meet this challenge and capture this opportunity are discussed later in this Application.

This increased challenge to Terasen Gas becomes self-evident when considering the following:

a) Provincial policy is focused on achieving GHG reductions and Energy Conservation.
b) Municipal policy is supporting provincial policy through commitment to the British Columbia Climate Action Charter.
c) Federal policy reflects a commitment to reduction in the rate of global warming.

This section will expand on these three points, while also explaining the implications to Terasen Gas.

a) Provincial policy is focused on achieving GHG reductions and Energy Conservation

The B.C. Provincial Government's energy and climate change policies will shape how energy is used by consumers within B.C. now and into the future. While the use of natural gas in the right application at the right time is goal-congruent with GHG reductions, the current statement of policy and related regulation has not matured to the level which sufficiently clarifies this point. Instead, the current state of evolution of policy initiatives, while ostensibly neutral as to energy choice, has the unintended consequence of discouraging the use of natural gas without particular regard to its benefits in certain end use applications. For instance, historic embedded cost of generation based electricity in rates

[20] For example, BC Energy Plan: A Vision for Clean Energy Leadership, Policy #3 (Encourage utilities to pursue cost effective and competitive demand side management opportunities) and Policy #4 (Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation) are policies objectives that give direction to the roles that utilities need to play.

versus market priced natural gas in rates, government mandated cross-subsidization of BC Hydro residential customers by other BC Hydro customer segments, and postage stamp tolling methodology for electricity in the province compared to distance related rates for natural gas, all send messages to the consumer that do not favour gas even where gas may be the right energy source for a particular application. In addition, provincial policies address GHG emissions on a provincial, rather than a regional basis. GHGs are a regional issue given that GHGs do not abide by political boundaries given the existence of interconnected energy grids. Examining GHGs on a provincial basis ignores the potential for gas consumption in efficient direct use applications in BC in order to reduce GHG emissions elsewhere in the region.

We expect that over time, policy clarification and regulation will serve to reduce this negative tension between some provincial policies and the overarching global goal of reducing the impacts of climate change. Nevertheless, these policies have significant repercussions for Terasen Gas' existing and future business.

The B.C. government's focus on reducing GHGs is reflected in a wide range of key initiatives and undertakings in recent years. These include:

- British Columbia - Energy Plan 2007: A Vision For Clean Energy Leadership
- 2007 Greenhouse Gas Reduction Targets Act
- B.C.'s Revenue – Neutral Carbon Tax and Emission Offset Regulation
- 2008 Amendments to the Utilities Commission Act
- Climate Action Plan
- Climate Action Team Report
- Province of British Columbia Strategic Plan 2009/2010-2011/2012
- Future Regulation (Western Climate Initiative)

Together these will shape the demand for energy by consumers in B.C., and thus impact how this energy is provided and delivered. Each is explained in more detail below.

(1) BRITISH COLUMBIA - ENERGY PLAN 2007: A VISION FOR CLEAN ENERGY LEADERSHIP[21]

On February 27, 2007 the B.C. government released a new Energy Plan: A Vision for Clean Energy Leadership. The Energy Plan indicated that the world had focused its attention on the critical issue of global warming, the British Columbia government decided to demonstrate the province's commitment to the production of clean energy and reduction of GHG emissions in the province, by leveraging the

[21] See Appendix C-2 for a copy of Energy Plan 2007: A Vision for Clean Energy Leadership, p. 3

province's key natural strengths and competitive advantages involving clean and renewable sources of energy.[22]

The Energy Plan of 2007 builds on the successes of the 2002 Energy Plan: Energy for Our Future: A Plan for BC. The Energy Plan 2002 had the following policy cornerstones:

- Low electricity rates to be assured by entrenching the benefits of publicly owned assets, independently regulating British Columbia Hydro and Power Authority ("BC Hydro") rates and outsourcing services where economic.
- To promote secure and dependable energy, reliability standards would be maintained, new supplies were to be developed and the Commission would be strengthened.
- To increase opportunities for the private sector, independent power was to be developed and ongoing support provided for the oil and gas industry.
- Environmental responsibility was to be assured through a clean energy goal, new price signals for conservation, clear emission standards and other strategies. [23]

Another policy item that was laid out in the Energy Plan of 2002 was *"natural gas marketers will be free to sell directly to residential and small commercial natural gas customers"*.[24] This specific policy item led to the establishment of the Terasen Gas Commercial Unbundling Program in April 2004 and ultimately to the Terasen Gas Customer Choice Program for residential customers, which started on May 1, 2007. See Part III, Section B, Tab 1 for more details on TGI Unbundling Program. The design and the implementation of the Unbundling Program is an example of how Terasen Gas plays a leadership role in moving government policy forward.

The Energy Plan of 2007 continues to build on the policies that were outlined in the Energy Plan of 2002. The Energy Plan of 2007 has the following goals and objectives, each of which present challenges and opportunities for Terasen Gas.[25]

a) Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.

22 See Appendix C-2 for a copy of Energy Plan 2007: A Vision for Clean Energy Leadership
23 See Appendix C-3 for a copy of Energy Plan 2002: Energy for Our Future: A Plan for BC, page 12
24 See Appendix C-3 for a copy of Energy Plan 2002: Energy for Our Future: A Plan for BC, page 9
25 See Appendix C-2 for a copy of Energy Plan 2007: A Vision for Clean Energy Leadership

The B.C. Government set a goal to reduce the growth in electricity demand so that by 2020, 10,000 gigawatt-hour ("GWh") of currently forecast needs would be met through demand reduction measures. This includes energy efficiency, conservation, and other demand-side solutions.

b) *Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.*

The Government is to ensure that all parties that help to deliver programs and initiatives to consumers have a coordinated approach.

c) *Encourage utilities to pursue cost effective and competitive demand side management opportunities.*

Under this Energy Plan, utilities in B.C. are to pursue all cost effective investments in demand-side management ("DSM"). Utilities are also encouraged to develop a diversified portfolio of programs to ensure all ratepayers can benefit from these programs. In particular, program development should consider how to make DSM programs accessible to residential ratepayers across all income levels.

d) *Explore with BC utilities new rate structures that encourage energy efficiency and conservation.*

All utilities are asked to explore, develop and propose to the Commission additional innovative rate designs that encourage efficiency, conservation and the development of clean or renewable energy. These include stepped rates for other rate classes, interruptible/curtailable rates, critical period rates, clean electricity supply rates, tariffs focused on promoting energy efficient new construction and others. Part of this work includes consideration of the benefits of 'smart' or advanced metering technology.

e) *Implement Energy Efficiency Standards for Buildings by 2010.*

To achieve energy conservation, government is determined to work with industry, local governments and other stakeholders to prepare and implement cost effective energy efficiency standards for buildings. Provincial energy efficiency building standards are needed to achieve energy efficiency and conservation targets and to support the goal of self-sufficiency, including commitments under BC Hydro's current Integrated Electricity Plan.

f) *All new electricity generating facilities constructed in British Columbia will have net zero greenhouse gas emissions.*

The B.C. government's objective is to effectively use the province's rich energy resources such as hydro electricity, natural gas and coal, preserving B.C.'s environmental standards, while upholding the province's quality of life for generations to come. The government made a commitment that all new electricity generation projects developed in British Columbia and connected to the grid would have zero net GHG emissions. In addition, any new electricity generated from coal must meet the more stringent standard of zero GHG emissions.

g) By 2016, existing thermal generating power plants will achieve zero net greenhouse gas emissions.

For existing plants, the government will set policy around reaching zero net emissions by 2016 through carbon offsets. It clearly signals the government's intention to continue to have one of the lowest GHG emission electricity sectors in the world.

h) Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.

The BC Energy Plan for 2007 commits to maintaining clean or renewable electricity generation contributing 90 per cent of total generation which places the province among the top jurisdictions in the world. Clean or renewable resources include water power, solar energy, wind energy, tidal energy, geothermal energy, wood residue energy, and energy from organic municipal waste.

i) Ensure self-sufficiency to meet electricity needs by 2016, plus "insurance" power to supply unexpected demand thereafter

The government notes that achieving electricity self-sufficiency is fundamental to B.C.'s future energy security and will allow the province to achieve a reliable, clean and affordable supply of electricity. In this regard the government committed that British Columbia will be electricity self-sufficient by 2016 and appropriate measures will be taken to ensure BC Hydro achieves this goal.

j) New provincial public sector buildings will be required to integrate environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.

To achieve the goal of reducing GHG emissions the Climate Action Team was to define a number of *"indicators of integrated environmental design"* (i.e. greenhouse gas, energy, water, building materials and transportation footprint). The indicators would be calculated on a regular basis by conducting audits of all existing, publicly funded buildings of a minimum size, and for all new construction projects. The audits to be completed prior to 2010 will be used to establish new integrated environmental design standards that will apply to all buildings that receive new funds from the Province.

k) Increase participation in the Community Action on Energy Efficiency program and expand the First Nations and Remote Community Clean Energy program.

The Energy Plan for 2007 intends to increase provincial government partnership with local governments to encourage energy conservation at the community level through the Community Action on Energy Efficiency Program and the expanded First Nations and Remote Community Clean Energy program. This will involve promoting energy efficiency and community energy planning projects, and providing direct policy and technical support to local governments through a partnership with the Fraser Basin Council.

The Energy Plan for 2007 sets ambitious targets and also sets out a strategy for reducing the province's GHG emissions and a commitment to unprecedented investments in alternative energy technology.

As the 2007 Energy Plan states:

> *"It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of alternative energy sources with natural gas include solar thermal and geothermal. Working with municipalities, utilities, and other stakeholders the provincial government will promote energy efficiency and alternative energy systems, such as solar thermal and geothermal throughout the province."*[26]

These policies are commendable, as they emphasize energy efficiency and conservation, and an integrated approach in finding energy solutions to reduce GHG emissions, objectives which TGI supports.

Yet these policies have also had the effect of putting Terasen Gas' traditional natural gas business at risk if Terasen Gas was to take a "do nothing approach". Without taking action, TGI could see a continued

[26] See Appendix C-2 for a copy of Energy Plan 2007: A Vision for Clean Energy Leadership, page 21

decline in total throughput volume flowing in the Terasen Gas natural gas distribution system. Over the long term, a decrease in throughput volume leads to higher unit delivery costs, which make natural gas more costly for customers, all else equal, and which would result in sub-optimal net GHG and other emissions.

(2) 2007 GREENHOUSE GAS REDUCTION TARGETS ACT ("GGRTA")

As part of the B.C. Throne Speech delivered on February 13, 2007, the government first announced targets for provincial GHG reductions.[27] The GGRTA put into law the most aggressive GHG emission reduction targets in North America effective January 1, 2008. The targets set by the GGRTA are as follows:

- To reduce B.C. greenhouse gas emissions by 33 per cent of 2007 level by 2020.
- By 2050 and for each subsequent calendar year, B.C. greenhouse gas emissions to be at least 80 per cent less than the level of those emissions in 2007.
- The provincial government, including all its departments, to become carbon neutral by 2010.
- By December 31, 2008, the minister must, by order, establish B.C. greenhouse gas emissions targets for 2012 and 2016. [28]

On November 25, 2008 further GHG interim targets were set by Ministerial Order as follows:

- 2012 – six per cent below 2007; and
- 2016 – eighteen per cent 2007 levels.

(3) B.C.'S REVENUE- NEUTRAL CARBON TAX AND EMISSION OFFSET REGULATIONS

The B.C. government was the first in North America to introduce a consumer–based carbon tax effective July 1, 2008. The tax encourages individuals and businesses to make more environmentally responsible choices; thus, incenting reduced use of fossil fuels and related emissions.[29]

The carbon tax applies on the purchase of fossil fuels in British Columbia, such as gasoline, diesel, natural gas, heating fuel, propane and coal. The tax starts at \$10/tonne of CO2e and will reach \$30/tonne of CO2e by 2012 by which time natural gas consumers in B.C. will be paying a \$1.50 per gigajoule ("GJ") in carbon tax. It is projected that the tax will contribute revenues to the Province, of

[27] See Appendix C-4 for a copy of Speech from the Throne 2007
[28] See Appendix C-5 for a copy of Bill 44 - 2007 Greenhouse Gas Reduction Targets Act
[29] See Appendix C-6 for a New Tax Cuts for British Columbians Beginning July 1

about \$1.85 billion over the first three years.[30] The carbon tax gives customers in British Columbia a choice on how they wish to adapt their behaviour to reduce their consumption of fossil fuels and is expected to help the government of B.C. achieve about 7.5 per cent of the government's legislated reductions by 2020.[31]

The province's further commitment to GHG reduction was reinforced when the B.C. government enacted the Emission Offsets Regulation in December 2008. These offset regulations were enacted to address the quality of GHG offsets in British Columbia in terms of the GGRTA.

The emission offset regulation sets out requirements for GHG reductions and removals from projects or actions to be recognized as emission offsets for the purposes of fulfilling the provincial government's commitment to carbon-neutral public sector by 2010.

The GGRTA helps to ensure that the GHG emission reduction targets are met. The detailed guidance document to the regulation is being prepared by the Ministry of Environment for publication in 2009.

Together the provincial reduction targets, the carbon tax and the emission offsets regulation present new challenges for Terasen Gas. The emissions from natural gas consumption within B.C. count against the GHG reduction target, while natural gas' primary competitive energy alternative – electricity – is deemed to be clean and therefore accounts for virtually no GHG emissions in B.C vis a vis the target. These regulations result in further competitive challenges for TGI and therefore impact the customers of TGI.

How these regulations will work with the Western Climate Initiative ("WCI") cap and trade system is still yet to be determined by government in the coming year.[32] Harmonization with federal regulation is also yet to be determined. Further details on the WCI follow in this section.

(4) 2008 AMENDMENTS TO THE UTILITIES COMMISSION ACT

To demonstrate the province's renewed focus on energy conservation and climate change and to empower the Commission to ensure utilities undertake efficiency and conservation measures in their

30 See Appendix C-7 for a copy of B.C. introduces carbon tax, p. 2
31 See Appendix C-7 for a copy of B.C. introduces carbon tax, p. 2
32 BC Hydro, Final Argument 2008 LTAP, dated April 9, 2009, pages 44-45 states: Pursuant to section 84 of the Carbon Tax Act, the B.C. Cabinet may with respect to a car fuel or combustible that is the source of the GHG emissions, provide for a regulation that exempts from the payment of the tax, or refunds all or part of the tax paid, subject to compliance obligations under the Carbon Tax Act and the new offset requirement for electricity generation under the Emissions Standards Act.

operations, the B.C. government in 2008 enacted amendments to the Act to reflect the following "government's energy objectives":

- to encourage public utilities to reduce greenhouse gas emissions;
- to encourage public utilities to take demand-side measures;
- to encourage public utilities to produce, generate and acquire electricity from clean or renewable sources;
- to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility;
- to encourage public utilities to use innovative energy technologies; and
- to encourage public utilities to take prescribed actions in support of any other goals prescribed by regulation. [33]

The Commission is required to consider government's energy objectives in the context of long-term plans, applications for a Certificate of Public Convenience and Necessity ("CPCN") and applications for approval of expenditure schedules. The amendments clearly positioned utilities as being on the front lines of implementing policies that encourage energy efficiency and the reduction of GHGs.

Further regulation that is administered by the BCUC relates to Demand-Side Measures Regulation.[34] These regulations were modified by ministerial Order No. 271 on November 6, 2008. Key changes to the regulation are:

- A public utility's plan portfolio is adequate for the purposes of the Act only if the plan portfolio includes all of the following:
    - A demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption; and
    - If the plan portfolio is submitted on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations.

The Province had previously removed a significant barrier to utilities pursuing cost-effective demand-side management by introducing the 2003 amendments to the Act in which a revised Section 60 (1) (b) included the provision that the Commission must have due regard in setting a rate that the public utility is provided, *"a fair and reasonable return on any expenditure made by it to reduce energy demands*".

[33] See Appendix C-8 for a copy of Bill 15 – 2008 Utilities Commission Amendment Act
[34] See Appendix C-9 for a copy of Demand-Side Measures Regulation

This change removed a potential financial disincentive for utilities to make expenditures to reduce energy consumption over investments in system expansion to accommodate load growth.

These amendments further reinforced that utilities such as Terasen Gas should take a leading role in implementing policies that encourage energy efficiency and the reduction of GHGs. See Part III, Section C, Tab 3 for details relating to TGI's response to these new DSM regulations.

(5) CLIMATE ACTION PLAN

Both the 2007 Energy Plan and the more recently released Climate Action Plan[35] demonstrate the B.C. Government vision and resolve for B.C. to tackle climate changes and in doing so, change the way British Columbian's think and act with respect to energy usage. As an example, the message from the government in the Climate Action Plan states:

> *"Global warming is the challenge of our generation. How we respond will shape the future of not just our environment, but also our economy, our society, our communities, and our way of life. British Columbia is taking decisive action to ensure these changes are positive. Since 2007 we have built a solid framework that addresses climate action in four key ways:*
>
> - *We have entrenched greenhouse gas reduction in law, including a commitment to reduce B.C. emissions by one-third by 2020.*
> - *We are taking targeted action in all sectors of the B.C. economy to help reduce emissions and set the course for the new low-carbon economy of the future.*
> - *We are taking steps to help British Columbians adapt to the realities of climate change and its impact on the province.*
> - *We are beginning a process to educate and engage British Columbians. This includes holding public forms and developing our LiveSmart BC initiative to support individuals, families, communities, business and industry to make cleaner choices and help.*
>
> *We are making good progress. In fact, independent economic modeling estimates that the climate action initiatives we have already announced will take us approximately 73 per cent of the way to our 33 per cent 2020 reduction target".*[36]

The Climate Action Plan maintains a consistent message from the provincial government about the commitment it has to reduction of GHGs and mitigation of climate change. As the summary of the Climate Action Plan suggests, *"we are taking action in all sectors of the BC economy to help reduce*

[35] See Appendix C-10 for a copy of Climate Action Plan
[36] See Appendix C-10 for a copy of Climate Action Plan, page 1

emissions". Given that about 15 per cent of B.C. GHG emissions come from the direct consumption of natural gas by customers, there can be no doubt that these policies will have a meaningful impact on Terasen Gas' natural gas business.[37] The prudent approach is for Terasen Gas to take proactive steps to address the impact of these policies. Please see Part III, Section C, Tab 3 for Terasen Gas responses to these policies.

(6) CLIMATE ACTION TEAM REPORT

To help the Province reach its goals relating to GHG, the British Columbia's Climate Action Team ("CAT") was established in November 2007.[38] On July 28, 2008, a report entitled: "Meeting British Columbia's Targets", was released by the CAT. In this report the CAT outlines 31 recommendations that could be taken to help the Province reach its GHG reduction targets. The specific policy recommendations that could have a direct impact to Terasen Gas and its customers are:

- Increase the British Columbia tax after 2012 if required to achieve the emission targets, in a manner that aligns with the policies of other jurisdictions and key economic factors.
- Develop, in collaboration with public and private partners, a comprehensive, multidimensional public engagement and outreach campaign that will: 1) educate British Columbians about the importance of climate change and the policies that are necessary to address this issue and 2) help British Columbians reduce their own greenhouse gas emissions in the most efficient way possible, and 3) make British Columbian's aware of the incentives and savings available by taking action on climate change.
- Update B.C.'s Green Building Code at least every three years to ensure B.C.'s code is a leader among North American energy codes.
- Require that, by 2016, all new publicly-funded buildings in the province have net-zero GHG emissions and that by 2020 all new houses and building have net-zero GHG emission.
- Introduce an aggressive energy efficiency and renewable energy program for houses and buildings, combining incentives and regulatory approaches and coordinated across governments and utilities.

All of the above recommendations have the intent of reducing fossil fuel use within homes and business, which by their very nature impact Terasen Gas by shaping customers' behavior regarding energy use.

[37] In 2006, TGI customers consumed 210,150,414 GJ's which converts into 10.507 million tonnes of GHG or about 15% of the 69 million tonnes of GHG produces in BC .

[38] See Appendix C-11 for a copy of Climate Action Team Report, page 2

An example of how these recommendations and other provincial policy objectives can influence customers' choices around energy consumption comes in the form of the University of British Columbia ("UBC") issuing a request for proposal to explore alternative energies at UBC. According to the public information provided by UBC, UBC Utilities produce steam currently on campus with four natural gas fed steam boilers. Two of the four steam boilers are scheduled to be replaced in the next seven years and UBC Utilities is aggressively looking to alternative non-polluting technologies to heat campus and ancillary tenant buildings.[39] One of the reasons behind why UBC is exploring this avenue is to support the objective to ensure carbon neutrality in all provincial public sector operations.

Thus, the CAT recommendations and government policies seem to be influencing and shaping purchasing decision of customers that were historically natural gas customers, and prompting them to consider alternate choices.

(7) PROVINCE OF BRITISH COLUMBIA STRATEGIC PLAN 2009/10 – 2011/12

In February, 2009, the Province of B.C. released its "Strategic Plan 2009/10 – 2011/12". This plan continues B.C.'s strong commitment as a "champion for climate change".[40] The plan goes on to say: *"B.C. has charted its course on climate change, with the establishment of its legislated goals for carbon emissions and greenhouse gas emissions. Our strategies developed over the last few years outline our plans and targets on everything from energy, bio-energy, agriculture, mountain pine beetle, to water, air, transit, and construction. Over the coming years, we will be focusing our efforts on implementing these strategies in order to achieve our objectives."*[41]

(8) FUTURE REGULATION

Energy and environmental policies are evolving and B.C. is taking the lead in setting standards. British Columbia has set ambitious emission reduction targets with the intention of transforming B.C. to a 'green energy' economy.

Like other responsible corporate citizens, Terasen Gas must continually review and evolve its environmental governance efforts in order to remain compliant with changing legislation, regulatory requirements, and government initiatives. Some of the challenges Terasen Gas must prepare for relate to future carbon emissions regulation are set out below.

---

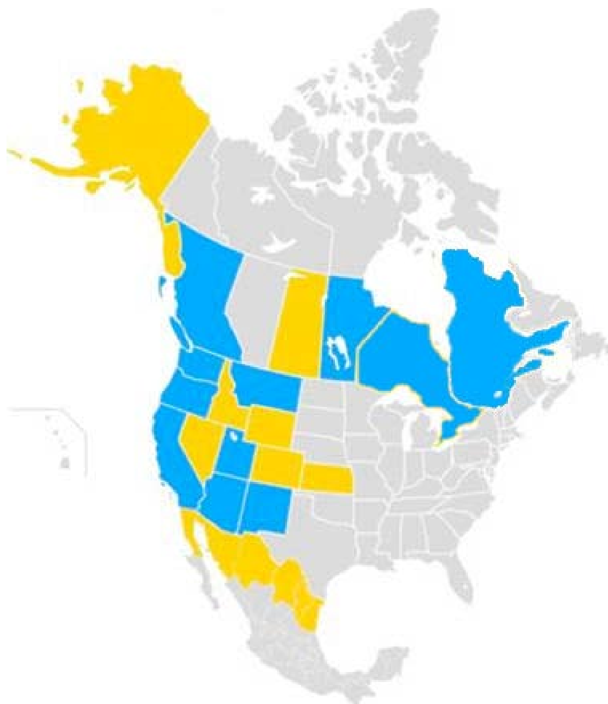
39 See Appendix C-12 for a copy of UBC Utilities Alternative Energy Project
40 See Appendix C-13 for a copy of Province of British Columbia Strategic Plan, page 1
41 See Appendix C-13 for a copy of Province of British Columbia Strategic Plan, page 38

(a) Incoming Legislation: Western Climate Initiative

British Columbia joined the WCI in 2007. The WCI is a partnership between seven U.S. states and four Canadian provinces (See Figure A-1, below).

Figure A-1: Province of B.C. Joins the WCI from its Inception

Western Climate Initiative Region



Yellow = Observer; Blue = Partner

WCI members have agreed to develop, among other things, a common framework for reporting and reducing GHG emissions. The region has committed to an overall emission reduction of 15 per cent below 2005 levels by 2020.

A substantial component of achieving this goal will occur through the development of a cap and trade system. Cap-and-trade functions by setting an overall limit on emissions for a region or economy the "cap". WCI Partners' caps will be determined based on individual targets, such that the limit for captured industries in 2020 will relate to a specific number of emitted tonnes.

Once the cap is set, each jurisdiction is provided an 'allowance budget', such that each 'allowance' represents one tonne of GHG emissions. While the specific details of how these allowances are obtained by captured sectors have yet to be determined, the eventual goal is that a declining number of allowances are available over time.

Each captured facility must obtain allowances for every tonne of their own emissions. Allowances are traded at market values such that those facilities that reduce beyond their regulated target are able to sell allowances at market rates. This ensures that the lowest cost emission reductions are achieved across the economy.

WCI reporting rules will require submission of a detailed, auditable emissions inventory starting with the 2010 calendar year. Terasen Gas understands that B.C.'s own Reporting Regulation under the Greenhouse Gas Reduction (Cap and Trade) Act will require reporting for the 2009 calendar year.

Development and management of inventories that will meet the stringent auditing requirements of a cap and trade system will require sophisticated software, owing to the scope of the Terasen Gas inventory and the level of transparency that will be necessary. This has been confirmed by previous voluntary audits of Terasen Gas GHG inventories.

Cap and trade, which will begin on January 1, 2012, will measure combustion, vented and fugitive emissions from nearly all of Terasen Gas' facilities. Compliance with B.C.'s aggressive targets will involve substantial strategic development around carbon management, and will require involvement in the cap and trade carbon market.

WCI, as well as the Waxman-Markey cap and trade bill at the US federal level, propose to make local distribution companies ("LDCs") the point of regulation for smaller customers (i.e. residential, commercial and industrial emitters below the regulatory threshold) under cap and trade. Under this model, LDCs will be responsible for purchasing allowances on behalf of their customers. How these cap and trade models work with the B.C. carbon tax will be determined in the coming years.

(9) CONCLUSION: PROVINCIAL POLICY FOCUSED ON REDUCING GHGS AND LEADING TO NEW CHALLENGES FOR TGI

The province of British Columbia is providing leadership by setting the course around developing targets and action plans to reduce GHG emissions so that others can follow.

TGI acknowledges that the public has accepted that GHG emissions contribute to climate change and that action must be taken. Terasen Gas is also committed to being part of the solution by helping customers have access to the energy they need while simultaneously meeting the province's legislative objectives and goals. Yet it is also clear that these policies present challenges to Terasen Gas' existing business, which could translate into increased costs for Terasen Gas customers if left unchecked. It is important for Terasen Gas to undertake and explore new initiatives that support government policy but at the same time help our customers find energy solutions that meet their changing needs.

In October, 2008 a report by the Canadian Gas Association ("CGA"), working in conjunction with Terasen Gas and Pacific Northern Gas, "A Vision for British Columbia's Energy Future: Smart Gas Strategies"[42], described three approaches, which build upon each other to improve the energy system. These three approaches are:

- Use available energy efficiently.
- Introduce alternative energy options.
- Move towards integrated community energy solutions.

Terasen Gas supports this logic path to reducing GHG emissions, while accommodating ongoing gross domestic product ("GDP") and population growth in B.C.

In response to these polices and realities, TGI has brought forth new energy alternatives for customers to help them and therefore the province of B.C. meet its energy objectives and goals. See Part III, Section C, Tab 3 for more details on new customer energy solution offerings.

Provincial energy and environmental policies are further supported by actions at the Municipal Government level. This is discussed in the next section.

b) Municipal Government Policy Also Committed to Provincial Energy Goals

Not only has the province of B.C. shown leadership in establishing energy and climate change objectives, local governments within B.C. are supporting these objectives by committing to the British Columbia Climate Action Charter.

(1) BRITISH COLUMBIA CLIMATE ACTION CHARTER

To commit B.C. Communities to the goal of attaining carbon neutrality by 2012, the Province, local governments and the Union of B.C. Municipalities ("UBCM") from across the province of B.C., signed a Climate Action Charter (the "Charter") on September 26, 2007.43 This charter committed local

[42] See Appendix C-14 for a copy of A Vision for British Columbia's Energy Future: Smart Gas Strategies
[43] See Appendix C-15 for a copy of British Columbia Climate Action Charter

governments to measuring and reporting their community's GHG emissions profile and to create more compact energy efficient communities. The provincial government realized that working in partnership with local governments would be more effective in reducing GHGs. Sixty-two communities initially signed the Charter and more signatures were expected to follow.[44]

To support the climate change initiatives, UBCM and the provincial government have *"established a Joint provincial-UBCM Green Communities committee and Green Communities Working groups to define a range of actions that can effect climate change, build local government capacity to plan and implement climate change initiatives, support local government in taking actions to make their own operations carbon neutral by 2012 and share information to support climate change initiatives"*.[45]

By March 31, 2009, as government efforts to fight climate change intensified, 174 local governments had signed the British Columbia Climate Action Charter demonstrating the importance and seriousness government attached to the issue of climate change throughout the province. The Charter should also result in the creation of economic benefits in the communities.[46]

This agreement and commitment by both provincial and local government is consistent with past messaging from organizations as such Metro Vancouver (formerly Greater Vancouver Regional District). For instance, the Air Quality Management Plan for Metro Vancouver, titled "Clean Air, Breathe Easy", dated September 2005 states on page 1:

> *"Actions that reduce emissions of common air contaminants and increase energy efficiency will be the most sustainable. Greater reliance on renewable energy sources and technologies with low or no emissions will directly benefit public health, the environment, tourism and agriculture."*

The policies pursued by municipal governments further encourage energy consumers to reduce their use of fossil fuels, including natural gas, or to consider alternatives entirely. These objectives and goals present challenges to Terasen Gas' traditional business.

c) Federal Government Policy Direction

Canada's Federal Government is committed to fight the growing global warming reality. The federal government has concluded that energy use and supply have made the greatest impact on the

[44] See Appendix C-16 for a copy of B.C. Communities Commit to Carbon Neutrality, p. 1
[45] See Appendix C-16 for a copy of B.C. Communities Commit to Carbon Neutrality, p. 1
[46] See Appendix C-17 for a copy of List of Local Governments who have signed B.C. Climate Action Charter

environment of any human activity, particularly regarding global warming, and has committed it to take action to reduce the rate at which global warming is taking place.

To achieve this, the federal government has put in place policies and objectives that, while not currently accompanied by legally binding targets, are nevertheless a strong indication that they are committed to the above goal.

The Federal government has outlined the following goals and objectives in recent years:

- Climate Change Plan 2005 – Moving Forward on Climate Change: "A Plan for Honouring Our Kyoto Commitment".
- Climate Action Plan 2007: "Turning The Corner".
- Speech From the Throne: To Protect Canada's Future.

Theses are discussed in more detail below.

(1) CLIMATE CHANGE PLAN 2005 - MOVING FORWARD ON CLIMATE CHANGE: "A PLAN FOR HONOURING OUR KYOTO COMMITMENT"

As a step towards the implementation of the Kyoto Protocol, after Canada's ratification in November 2002, the federal government on April 12, 2005 released a new national Climate Change Plan entitled 'Moving Forward on Climate Change; A Plan for Honouring our Kyoto Commitment'. The plan combined regulatory, negotiated and incentive based measures to reduce GHG emissions and its key elements include the following:

a) The large Final Emitters System. This was a mandatory market driven program aimed at reducing greenhouse gas emissions by 45 megatonne ("Mt") in mining, manufacturing, oil, gas and thermal electricity, which account for about half of national emissions.
b) Auto Sector. The auto manufacturers agreed in a Memorandum of Understanding with government to reduce CO2, methane, nitrous oxide, and hydroflourocarbon emissions from light duty passenger cars and trucks by 5.3 Mt or 6 per cent below business-as-usual by 2010.
c) Climate Fund. The government intends to purchase 75-115 Mt of reduction credits a year, up to 40 per cent of the total reduction needed in 2008-2012 through a new Climate Fund. Priority was to be given to domestic reductions from farmers, forestry companies, municipalities, and other sources. The government agreed to allocate CAD$1 billion per year over the next 5 years and projects funding of $4 billion-$5 billion for the 2008-2012.

d) Partnership Fund. A new Partnership Fund was set up to support government-to-government agreements at the federal, provincial, and territorial levels to jointly pursue emission reduction projects, including short and long-term climate change technology investments and infrastructure development. The government agreed to allocate CAD$50 million per year for the next five years and anticipated that funding of CAD$2 billion-$3 billion could result in 55-85 Mt annual reductions in 2008-2012.

e) The Wind Power Production Incentive was quadrupled to provide CAD$200 million over the first five years to produce a projected 4,000 megawatt ("MW") increase in wind generating capacity. The Renewable Power Production Incentive was to provide CAD$97 million over five years to increase capacity from small hydroelectric, biomass, tidal, and other renewable sources by a projected 1,000 MW. [47]

This plan demonstrated the federal government's commitment to work closely with provinces, territories, the industry sector, and other stakeholders to preserve and protect the environment from the effects of GHG emissions and air pollutants to establish a green economy.

(2) CLIMATE ACTION PLAN 2007: "TURNING THE CORNER"

To show its commitment to drastically reduce GHG emissions and air pollution, the Federal government on April 26, 2007 released an action plan called "Turning the Comer". The plan puts in place one of the toughest regulatory regimes in the world which are as follows:

- To reduce GHG emissions by 20 per cent by 2020 to the 2006 levels and
- To reduce GHG emissions by 70 per cent by 2050 to 2006 levels. [48]

The targets for industrial greenhouse gas emissions are as follows:

Existing facilities

- 18 per cent reduction from 2006 emission intensity [49]starting in 2010
- 2 per cent annual improvement thereafter

New facilities

- 3-year grace period
- Clean fuel standard and

[47] See Appendix C-18 for a copy of Canada's Climate Change Plan
[48] See Appendix C-19 for a copy of Climate Change Plan 2007
[49] Emission intensity is defined as a ratio of greenhouse gas emissions per unit of economic activity (GDP or unit of production such as barrel of oil).

- 2 per cent annual improvement

To ensure successful implementation the government introduced mandatory and enforceable actions across a broad range of sectors. The emission intensity approach ties the emission targets to production. This is a plan which recognizes the need to reduce GHG emissions while growing the economy.

(3) SPEECH FROM THE THRONE: TO PROTECT CANADA'S FUTURE

The speech from the throne "*To Protect Canada's Future*" delivered on November 19, 2008, reinforced the federal government's commitment to the provision of secure energy supply and fighting the challenges of climate change among other objectives.[50] It sets the direction provinces, local governments and communities are to take in the development of energy resources in an environmentally responsible manner.

The following measures are to be taken by the federal government in support of this commitment.

a) Support the development of cleaner energy sources. The development of natural gas reserves that lie beneath Canada's North was to be encouraged by reducing regulatory and other barriers to extend the pipeline network to the North. This is expected to bring jobs to northern Canada and create employment across the country.
b) Support the establishment of nuclear energy, should provinces choose to advance new nuclear plants.
c) Commit to reducing greenhouse gas emissions by 20 per cent below 2006 levels by 2020 while ensuring that Canada's actions are comparable to what United States, Europe and other industrialized countries undertake.
d) Set as an objective that 90 per cent of Canada's electricity needs should be provided by non emitting sources such as hydro, nuclear, clean coal or wind power by 2020.
e) Ensure protection of vital resources by legislating to ban water transfers or exports from Canadian fresh water basins.[51]

The foregoing recognizes the important role the federal government expects energy to play in the development of Canada going forward. The federal government is committed to use the country's rich and diverse energy resources such that they meet today and future generation's needs. The speech demonstrates the federal government's commitment to the provision of secure energy resources while

[50] See Appendix C-20 for a copy of Speech from the Throne 2008
[51] Ibid

tackling climate change issues to ensure business in Canada is carried out in an environmentally compliant manner and jobs are created for the benefit of the communities.

To advance the goal of reducing GHG emissions by 20 per cent from 2006 levels by 2020 the government of Canada on April 1, 2009 announced its intention to take action on each of the major sources of greenhouse gas emissions starting with the transportation sector, the biggest source of GHG emissions in the country. For the transportation sector, the government is to put in place regulations effective 2011 requiring that new passenger cars and trucks must be fuel efficient and should produce lower GHG emissions.[52]

Further, in a recent speech date June 4, 2009, made by Honourable Jim Prentice, Minister of the Environment stated the following related to climate change: "December is where the UN Climate Change process really crystallizes in Copenhagen, and Canada's goal is to be there to help secure a new global agreement on how we will move past Kyoto and deal with climate change. Copenhagen is effectively where the world will turn the page on Kyoto and look beyond 2012. It is our greatest hope that we will be successful in achieving an international consensus there to respond to what is increasingly recognized as the greatest environmental challenge of our time".[53]

(4) CONCLUSION

The federal government has demonstrated its commitment to fight against global warming by setting energy and environment polices which, although not legally binding, indicate the direction in which the federal government wants to move.

d) *Summary of Implications Related to Energy Policy from All Levels Government for Terasen Gas' Business*

The past several years British Columbia's provincial and municipal governments have sent a strong and repeated message through policy about their commitment to cutting GHG emissions, the main contributor to climate change. The federal government, while not tied to any binding legislation, has also signaled its intention to pursue these same goals through policy.

The desired outcome behind all of the policy initiatives is to reduce impacts of climate change and therefore, Terasen Gas is of the view that it is reasonable that the policy environment will mature over time. This maturation of policy should serve to ensure that the actions of British Columbians continually

[52] See Appendix C-21 for a copy of Government of Canada to reduce greenhouse gas emissions from vehicles
[53] Environment Canada – Media Room – 2009 Speeches Archives

migrate towards contributing to climate change goals without causing them economic disadvantage as compared to consumers in other regions. Terasen Gas is also of the view that provincial policy will also harmonize with those of federal and other governments in our region.

Terasen Gas agrees that action must be taken to address the climate change challenges we all face. TGI is also committed to being part of the solution by helping customers have access to the energy they need while simultaneously meeting the province's legislative objectives and goals. Terasen Gas also recognizes that, while laudable, these objectives and goals present challenges to Terasen Gas' traditional business. The result of these policies is that some members of the public and some policymakers in the province believe that the use of natural gas should be discouraged because its use results in GHG emissions.

A more nuanced consideration of the issues is required. There are applications for which gas is ideally suited, and gas is a clean alternative to other fossil fuels. The efficient consumption of natural gas in BC can result in GHG reductions elsewhere in the region. A complete energy picture involves using each energy form to its highest and best value across interconnected energy grids regardless of geographic borders. Integrating renewables with gas and electricity in variations which best fit a multitude of unique applications will help customers and communities respond to policy initiatives and public sentiment.

The new emphasis on climate change presents both obligations and opportunities for Terasen Gas to be a leader in assisting our customers to address these challenges. This Application also outlines a number of new initiatives that are aimed at providing customers with a range of energy solutions that are consistent with evolving government policy and public perception. The intended evolution of our business will protect the interests of our customers and our shareholder from consequences resulting from the rigorous pursuit of GHG policies that have not yet reached maturity. See Part III, Section C, Tab 3 for further details.

2. Expectations of Customers, Regulators and Stakeholders are Evolving, and Terasen Gas will have to take Action to Continue Meeting their Respective Needs.

The challenges presented to our traditional natural gas business by the current state of provincial, municipal and federal policy, on their own suggest that we should re-examine our business needs to ensure our long-term ability to meet the needs of energy consumers. The changing expectations and requirements that customers, stakeholders and regulators have of Terasen Gas makes a focused response even more imperative.

The discussion in the following section focuses on what customers expect from Terasen Gas related to customer care and meeting their energy needs. Meeting the energy needs of our customers crosses a broad spectrum ranging from the needs of an individual customer at a residential home to those of a community that is looking for an integrated energy solution. This section will also discuss how the public is increasingly concerned about public safety and security. These issues are addressed by looking at how regulators are mandating that Terasen Gas change to meet new codes and regulations.

This section reviews the following areas:

a) Evolving Community Involvement in Energy Choices
b) Growing Need for Increased Customer Care Activities
c) Increasing Public Concern about Safety and Security
d) Continuing Complexities in Aboriginal Rights

Terasen Gas is committed to meeting the needs of its customers and stakeholders. Yet if we are to do so then our business must take appropriate actions. Below these areas are discussed in detail.

a) Evolving Community Involvement in Energy Choices

Traditionally, end use customers simply purchased a new or used house without any concern or thought as to how the energy was delivered to the building. Gas and electrical energy were the common options. Customers were primarily concerned with the ongoing cost of energy. They thought little about the energy delivery system or whether or not the production of energy contributed to climate change. Energy was produced on a macro scale in large scale electrical generation facilities and natural gas production fields and then transported to end use customers.

This attitude is now changing in notable and significant ways. While many customers still do not have an interest in energy complexities, more and more are showing an interest in where energy comes from and how it is consumed. When broader policy targets enter the mix, as was previously described, communities have also started to become involved in decisions on how their own constituents use energy. This is impacting how Terasen Gas pursues its business and how it serves its customers.

Communities are now developing their own sustainability plans, which include:

- Looking at how the region should use energy;
- Looking at how they can influence the use of energy in their jurisdiction; and
- Looking at how they can influence development, through bylaws, planning regulations, and community consultation that will impact building codes.

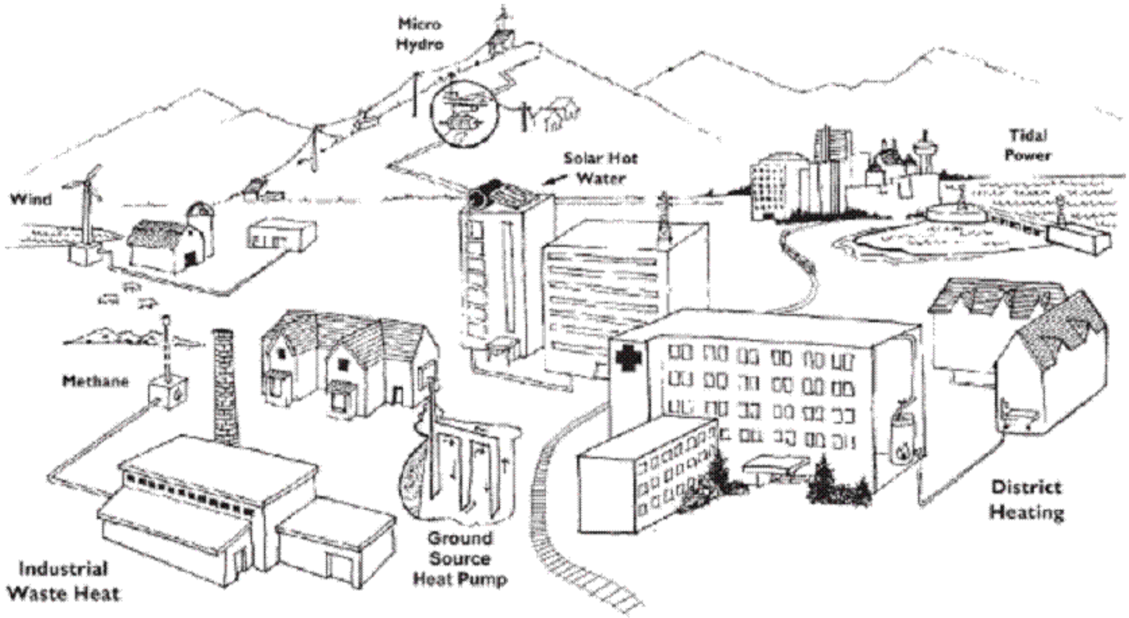
At the forefront of this change is Quality Urban Energy Systems of Tomorrow ("QUEST"). This group, a consortium of municipalities, provincial and federal governments, utilities and private industry, supported by stakeholders such as the Canada Green Building Council, Canadian Electricity Association, Canadian Energy Efficiency Alliance, CGA, Industry Canada, Natural Resources Canada, Ontario Power Authority, and Pollution Probe. [54] This consortium has been working together to promote an integrated approach for energy services in Canadian communities. QUEST White Paper I states that:

> *"The community, with its use of energy in houses, business, institutions, industry and transportation, is the most promising place to act.*
>
> *An integrated approach at that level allows balancing energy demand and supply between different sectors, accounting for the impact of one system versus the other, and leads to optimal results in providing community services.*
>
> *Integration of energy systems at the community level brings the maximum economic, social and environmental benefits".*[55]

In the QUEST community, all energy forms are integrated and interact with each other. This is demonstrated by the following figure.[56]

[54] Specifically Terasen Gas Inc., BC Hydro, and the Government of British Columbia participate in QUEST initiatives.
[55] See Appendix C-22 for a copy of QUEST White Paper I
[56] Ibid

Figure A-2: All Energy Forms Interact in a QUEST Community



Source: Green Municipalities - A Guide to Green Infrastructure for Canadian Municipalities; prepared for the FCM by the Sheltair Group, May 2001

For Terasen Gas to continue to participate and be successful in delivering energy in British Columbia, we must be involved in community energy planning and have the requisite resources to participate in a meaningful fashion. In addition, we must also be able to provide expertise about energy solutions that include not only natural gas but also alternative energy solutions and how best to integrate them.

Lastly, the majority of B.C. municipalities have committed to the provincial government to become carbon neutral by 2012.[57] In turn, this obligation has and will be making its way into local bylaws and thus changing the way developers must plan for energy requirements. Local governments have long been important partners for Terasen Gas, but they have now become even more crucial to the long-run success of the Company. By using a community, or QUEST approach, utilities can play a significant role in both developing community energy systems to meet customer needs and reduce the impact of climate change. Terasen Gas will need to play an important role in assisting communities and developers in understanding facts as well as identifying solutions. It is in the customer's best interest for Terasen Gas to be delivering these solutions given our broad geographic footprint, skilled workforce, knowledge and experience. Our customers' best interests are served by Terasen Gas being - and being

[57] See Appendix C-15 for a copy of British Columbia Climate Action Charter

perceived by municipalities and communities as - a provider of solutions for natural gas and/or alternative energy delivery.

b) Growing Need for Increased Customer Care Activities

The customer care function of Terasen Gas is a vital part of providing service to our customers, and consequently represents a core element of our business. It is the main point of interaction between customers and the Company in all aspects of our business. In order for the Company to continue to serve customers well, the customer care function needs to adapt and change as customers require new and different services. Underpinning this ability to provide service excellence is a technology platform.

A key emerging area of customer interest is energy conservation supported by more accurate and timely information related to energy consumption. Residential customers are interested in better understanding their home energy use and using that knowledge to manage their consumption and subsequent billing. This, combined with customer awareness related to their contribution to the carbon footprint, and specific initiatives particularly for government and institutional customers has resulted in demands for more timely and accurate information.

Further changes to our business requirements are expected over the next few years. In particular, Terasen Gas anticipates designing and developing new programs specifically targeting energy efficiency and conservation. This will require not only enhanced billing and tracking capabilities but also a highly knowledgeable workforce to support customer inquiries. In response to customer demand for enhanced billing and payment options Terasen Gas also requires technology changes to support these demands in a timely and cost effective manner.

In order to address these needs Terasen Gas, on June 2, 2009 applied to the BCUC for a CPCN for the Customer Care Enhancement Project. It contemplates the insourcing of core aspects of customer care services and the implementation of a new customer information system for January 1, 2012.

c) Increasing Public Concern about Safety and Security

Across North America, concerns regarding the reliability and safety of public infrastructure are growing. People are more aware of environmental and security issues, in addition to the aging of existing infrastructure. Public concern and expectations have increased pressure on regulators and code associations to enact increasingly stringent requirements. The specific codes discussed below govern the present and future operating requirements of the Company, with a strong focus on public, employee, property and environmental safety as well as system reliability. While compliance with safety regulations is the minimum performance standard expected to be achieved, Terasen Gas is committed to meeting the increasing safety expectations of the public by ensuring that programs and systems meet or, where appropriate, exceed regulatory requirements.

(1) B.C. OIL AND GAS COMMISSION ACT, B.C. PIPELINE ACT AND REGULATIONS (UNDERGOING CHANGE)

The Oil and Gas Activities Act will replace the Pipeline Act and the Oil and Gas Commission Act. The Oil and Gas Activities Act consolidates the powers and duties of the Oil and Gas Commission ("OGC") as well as the rules regulating persons carrying out an oil and gas activity in the province. It is unknown at this time what operating changes will be required by Terasen Gas when this Oil and Gas Activities Act is finalized.

(2) CANADIAN STANDARD'S ASSOCIATION ("CSA") CSA Z662 – OIL AND GAS PIPELINE SYSTEMS

CSA Z662 is the CSA standard for oil and gas pipeline systems. It defines minimum requirements throughout the lifecycle of transmission and distribution gas system assets including design, installation, and operations.

Integrity Management activities have been part of CSA Z662 since its inception. The goal of integrity management of gas distribution systems and pipelines is to provide safe, environmentally responsible and reliable service with focus on mitigating and managing the potential for external interference, failure and damage incidents. These incidents may result in an immediate unplanned release of gas or cause damage to a pipe, component or coating which increases the likelihood of an unplanned release in the future. Many of the clauses within CSA Z662 relate to designing, installing and maintaining plant to provide safe and reliable service.

Major incidents across North America, such as the 1999 Olympic Pipeline rupture due to pressure in Bellingham, Washington and the 2007 Kinder Morgan Canada oil pipeline rupture due to third party damage in Burnaby, B.C., have put safety concerns into the forefront of the minds of the public and regulators. Stakeholder groups want to ensure that asset integrity is at the highest reasonable standard including: robust processes and system and record keeping that is highly transparent. As a result, in Canada, the CSA has added Annex M & N to CSA Z662.

Annex M provides a framework for Distribution Systems Integrity Management Plans, but as of yet is not mandatory. Annex N introduces the requirement for a formal IMP for Pipeline Systems, which was formally adopted by the OGC as a requirement on August 26, 2006. Terasen Gas performed the majority of the items within the Annexes, and developed and implemented its formal IMP using these base activities and augmenting where appropriate. The resulting IMP covers all gas system assets, as required by Annex M and N.

The 2007 version of CSA Z662 also introduced Clause 10.2 Safety and Loss Management Systems as a mandatory requirement of the code and provides Annex A as an applicable template. Annex A sets out a recommended practice for a safety and loss management system applicable to design, construction, operation, and maintenance activities that can affect the safety of people or the protection of property or the environment. Clause 10.2 also suggests that companies may require a period of two years or more to reach compliance. Terasen Gas is in the process of accessing potential compliance gaps to this new requirement. Samples of other safety and emergency codes that must link into Annex A requirements include provincial and federal Emergency Acts, Environment Management Act (see below), fire codes, and safety standards (see below).

(3) CSA Z276 - LIQUID NATURAL GAS PRODUCTION, STORAGE AND HANDLING

CSA Z276 is the CSA standard for liquid natural gas production, storage and handling. It defines standards which govern Terasen Gas' LNG Plant operations. No significant changes have been introduced into this code over the PBR Period and none are anticipated in the near future. The new Mt. Hayes facility is being constructed to meet CSA Z276 compliance.

(4) CSA Z246 - SECURITY MANAGEMENT FOR PETROLEUM AND NATURAL GAS INDUSTRY SYSTEMS (ANTICIPATED RELEASE OCTOBER 2009)

Emergency planning agencies consider critical infrastructure such as natural gas facilities prime targets for terrorists and, as such, the CSA has drafted a new standard: CSA Z246.1, Security Management for Petroleum and Natural Gas Industry Systems to formalize requirements.

Enactment of CSA Z246.1 will bring new requirements designed to improve natural gas facilities protection from vandals and terrorist activities.

(5) CSA Z1000 – SAFETY MANAGEMENT SYSTEM AND WORKSAFEBC

Recent high profile accident investigations in B.C. and subsequent court cases have found that management systems based on compliance only, are inadequate. Regulators and the courts in Canada and throughout the western world are looking at standards agencies such as British Standards ("BSI"), American National Standards Institute ("ANSI") and CSA to provide guidance on how effective a company's safety program is.

CSA Z1000 is the CSA standard for safety management. It defines a framework for a safety management system which would allow a company to reduce accidents and risks, meet compliance and legal requirements and build a solid defendable due diligence.

Upon investigating management systems, the Terasen Gas Occupational Health and Safety group has concluded that the CSA Z1000 standard meets the needs of Terasen Gas and the existing management system, which meets the strict compliance requirements as set by WorkSafeBC, and will be reshaped to meet this new standard through 2009/2010.

(6) BC SAFETY AUTHORITY ("BCSA"): SAFETY STANDARDS ACT AND GAS SAFETY REGULATIONS

The BCSA administers a number of safety programs to fulfill its mandate of "*overseeing the safety of key technology areas*".[58] Certain activities at Terasen Gas are governed by the BCSA – Gas Safety Regulation. "*The Gas Safety Program regulates safety in the area of gas distribution*"[59] and other gas related matters (i.e. propane gas).

The BCSA change to the Procedures for Excavations section of the Gas Safety Regulation significantly impacts the operations of Terasen Gas. Prior to April 1, 2008, a gas company was given 3 days to provide gas system information requested by a third party. On April 1, 2008, the regulation was changed to state that "*on receiving a request under subsection (2) a gas company must provide the information requested within 2 business days*".[60] As a result of this code change, TGI has had to increase staff members handling such requests in order to meet the 2 day requirement.

(7) POWER ENGINEERS, BOILER, PRESSURE VESSEL AND REFRIGERATION SAFETY REGULATION

Pressure vessels were previously considered part of the piping system. An improved understanding of this code requires that these pressure vessels be registered with the BC Pressure Vessels branch, data files to be set up and inspections carried on a periodic basis pursuant to the American Petroleum Institute ("API") standard API 510 and the safety authority. API 510 is the recognized North American standard that covers the in-service inspection, repair, alteration, and rerating activities for pressure vessels and the pressure-relieving devices protecting these vessels and is an appropriate base for establishing the required pressure vessel related work. Terasen Gas will be working towards compliance through the 2009-2010 period.

[58] See Appendix C-23 for a copy of BC Safety Authority - Safety Programs
[59] See Appendix C-24 for a copy of BC Safety Authority - Gas Safety Program
[60] See Appendix C-25 for a copy of Safety Standards Act - Gas Safety Regulation

(8) ENVIRONMENTAL MANAGEMENT ACT

British Columbia places a high value on ensuring environmentally sound practices as demonstrated by its Environmental Management Act. The Act includes significant penalties for non-compliance in terms of environmental management.

One example of how the new environmental rules impact Terasen Gas deals with the Federal Species at Risk Act. The number of species which require special consideration and protection when activities are planned in areas they inhabit has increased. In addition, fines and penalties for non-compliance have increased. Since Terasen Gas regularly excavates in the ground to install pipe and other facilities, new measures are required to be taken to effectively and efficiently screen project areas prior to construction for the potential to impact protected species.

(9) 3RD PARTY REQUESTS FOR UPGRADES

As government, community and other utilities respond to their own issues with aging infrastructure, Terasen Gas has faced increased pressure to upgrade its assets as a result of these external infrastructure projects. This will continue as the 2010 Olympic and Paralympic Winter Games near and as infrastructure projects emerge as stimulus measures to ease the current economic downturn. Much of the cost of these projects can be recovered by billing the requestor, but there are several factors that affect the degree of cost sharing. Additionally, Terasen Gas is not in control of the schedules for road projects, which places demands on internal resources to make the necessary adjustments.

(10) SUMMARY

The specific codes, discussed above, as well as local bylaws govern present and future operating requirements of the Company. Terasen Gas places a high priority on public, employee, property and environmental safety as well as system reliability, and strives to comply, or when appropriate exceed, codes requirements. As codes change, operating practices of the Company, in some cases, also needs to change. Part III, Section B, Tab 1, The Past, discusses how Terasen Gas has met compliance during the PBR Period and Part III, Section C, Tab 6, O&M, discusses Terasen Gas' operating changes to address the 2010/2011 compliance needs.

d) Continuing Complexities in Aboriginal Rights

Uncertainty as to the nature and extent of aboriginal rights and title in B.C. and the lack of treaties create operational and regulatory complexity for Terasen Gas that must be managed.

There are very few treaties in British Columbia. Historical treaties only cover a relatively small part of B.C. (portions of Vancouver Island and the northeast corner of the province). There have been treaty negotiations in recent years but only three treaties have been completed. Due to the small number of treaties in B.C., there are many unestablished claims for aboriginal rights or title. This leads to uncertainty both as to the scope of the rights, and the area in which it is exercised.

B.C. recognizes approximately 285 different First Nations, Bands and Tribal Councils. The need to recognize and deal with Tribal Councils flows from the lack of treaties, making it more difficult to identify the appropriate aboriginal representative. The high number of aboriginal groups in British Columbia leads to overlapping territories and competing claims for aboriginal title, as well as strong differences in opinion as to the appropriate forum for reconciling aboriginal rights and title. There is division among BC First Nations as to whether to enter the current treaty negotiation process. Since TGI's activities span large parts of British Columbia, the large number of different aboriginal groups whose interests may overlap requires careful management by TGI when pursuing projects.

TGI needs to invest in the necessary resources to address properly the issues presented by asserted claims of aboriginal rights and title and the duty to consult and, if necessary accommodate.

3. Terasen Gas' Competitive Position Continues to Decline Relative to its Peers and Competitors

Terasen Gas' competitive position relative to peers and competitors continues to decline, presenting further challenges that we must meet.

Historically, consumers have made purchase decisions about what energy supply source they are willing to buy based on a numbers of variables. Historical decision criteria includes the cost of product, ease of use, and reliability. In addition to these historical decision criteria, the provincial GHG reduction targets have the potential to adversely change people's perception of natural gas over the long term. The targets may shift investment and consumption decisions of the consumer away from natural gas towards the consumption of electricity or other renewable energy alternatives (such as solar and geothermal).

Thus, direct use of natural gas for certain applications must overcome two hurdles before the buyer will make a commitment to investing in natural gas equipment. One is the economic test, comparing the historical and future natural gas operating costs and capital cost versus the competitive alternative. The second hurdle that needs to be overcome is related to the "green" perception of a product and how that product helps in the climate change challenge.

The gradual erosion of natural gas' cost advantage in B.C. versus electricity impacts TGI's growth in new customer additions, and also impacts existing customers' throughput levels. Natural gas market prices have improved relative to other energy commodities (such as oil) in the North America marketplace, but natural gas faces challenges in the B.C. marketplace due to the differing nature of how natural gas and electricity costs are reflected in rates. Increases in natural gas prices incent customers to reduce their energy consumption or look for cheaper alternatives to meet their energy needs. Both cases lead to reduced consumption levels on the natural gas system which negatively impacts existing customer's rates, all else being equal.

The following areas illustrate this reality:

a) Historical cost advantage of natural gas is declining
b) TGI competitiveness to electricity versus other jurisdictions is in decline
c) Forward looking operating cost advantage of natural gas is likely to decline
d) Demand for perceived "green" energy represents an additional challenge

When looking at natural gas competiveness, we need to consider both the operating cost (cost of the energy) and the cost of installing the equipment (capital or upfront costs).

These points are discussed below.

a) Historical Operating Cost Advantage of Natural Gas is Declining

One of the continuing challenges facing TGI is the decline in price advantage against electricity (the difference between lower natural gas rates compared to electricity rates) on an annual operating cost basis. Between 1998 and 2008, the price advantage of natural gas compared to electricity in B.C. declined from 63 per cent to 18 per cent[61], and yet its relative competitiveness to petroleum based products improved and its use as a fuel source for power generation increased substantially.

Annual operating costs for natural gas applications such as space and water heating may improve versus using electrical alternatives for these applications in the coming years with the establishment of the BC Hydro Residential Inclining Block ("RIB") rate that was implemented October 1, 2008. The carbon tax will be an offsetting factor to this improvement. Natural gas must also maintain a significant annual

[61] Figures in Appendix C-26: Competitive Rae Comparisions History 1998-2009, show 2009 but 2009 is not reflected in this calculation as the year is not complete and gas commodity may changes in the remaining months for 2009.

operating cost advantage compared to electricity to provide a payback on the upfront equipment cost difference of a natural gas heated home and one that uses electricity baseboards for space heating.

As shown in Appendix C-26: Competitive Rate Comparisons History 1998-2009, natural gas enjoyed a substantial price advantage versus electricity in the late 1990's throughout the three TGI regions (Lower Mainland, Inland and Columbia). In all three regions, the cost of natural gas to a customer in 1998 was less than half the cost of using electricity for the same applications. This price advantage has gradually declined as natural gas rates increased with rising commodity costs while electricity rates remained relatively constant.

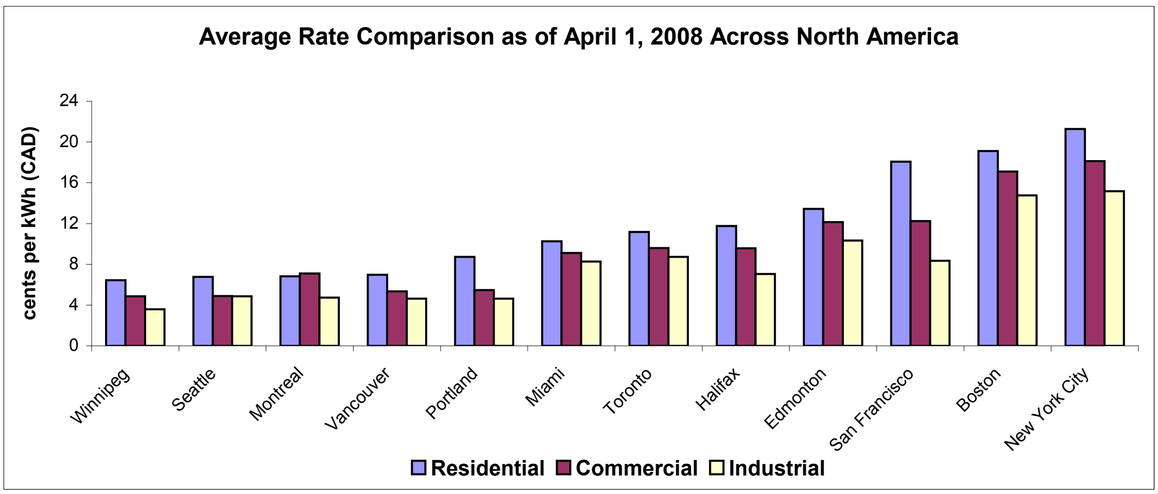
BC Hydro's electricity rates have remained relatively flat over this timeframe. Prior to 2004 BC Hydro was in an extended rate freeze period and was not subject to BCUC oversight. During the rate freeze period BC Hydro was able to absorb its cost pressures with decreasing costs in other categories such as declining interest rates and with profits from electricity exports. In the meantime electric load has continued to grow beyond the supply capabilities of BC Hydro's Heritage resources, necessitating the acquisition in recent years of new and more costly renewables. However, BC Hydro's rates are largely reflective of Heritage or historical costs of supply and continue to be among the lowest electricity rates in North America. With the establishment of the BC Hydro RIB rate, a customer's electricity rates will be determined based on the consumption level at the particular residential dwelling. In principle, the RIB represents a splitting of the allocated historical costs for the residential class into two rates, with the rate for the second step being higher, in order to promote energy conservation. Notwithstanding this design, the conservation impact is significantly dampened given the net revenue requirement quantum does not change, meaning that the RIB rate revenues serve to reduce the rate applying to the Step 1 rate.

The gradual erosion of the natural gas rate (not cost) advantage relative to electricity increases make throughput levels more challenging to achieve. Reduced consumption levels on the natural gas system negatively impacts exiting customer's rates, all else being equal.

The continued decline in the operating cost advantage from 63 per cent in 1998 to just 18 per cent in 2008 for natural gas versus electricity, its primary competition, combined with the lower capital and installation costs for electric baseboard heaters has created a challenging competitive market environment. The capital and installation costs for a new natural gas heating system typically range from three to four times higher than for electric baseboards. The difference in upfront capital cost for heating equipment and ducting makes the simple payback to the potential natural gas customer extend over a long period of time or exceed the expected life of that equipment.

One of the reasons for the decline in the price advantage that natural gas has had against electricity is how these products are priced in B.C. Natural gas commodity pricing for consumers in B.C. is market-based; in contrast a large percentage of the costs making up electricity rates are the low embedded costs of BC Hydro's Heritage generation facilities. Please see Figure A-3 below, which shows BC Hydro's electrical rates are among the lowest in North America.

Figure A-3: B.C. has Low Electricity Rates Compared to Most of North America



Rates are based on Hydro-Quebec's "Comparison of Electricity Prices in Major North American Cities"
Seattle rates are based on Seattle City Light

b) TGI Competitiveness to Electricity versus other Jurisdictions in Decline

TGI faces a higher level of price competition than many other gas distribution utilities in Canada and the Pacific Northwest. Figure A-4 below shows the natural gas versus electric price differential for TGI in the Lower Mainland and six other gas distribution companies, based on current residential customer rates. All companies who compete against market priced electricity enjoyed a price advantage ranging from approximately 2 per cent to 74 per cent as compared with a 32 per cent price differential for TGI. As Figure A-4 is taken at a specific point in time, the difference between rates among the companies will change over time.

Figure A-4: Comparison of Natural Gas versus Electric Price Advantage for Five Companies (2009)

	ANNUAL BILL - NATURAL GAS	ANNUAL BILL - ELECTRIC	GAS VS. ELECTRIC PRICE ADVANTAGE	
Terasen Gas (Lower Mainland)	$1,118	* $1,641	-32%	lower
Puget Sound Energy - Washington	$1,476	$2,530	-42%	lower
Northwest Natural Gas - Oregon	$1,604	$2,142	-25%	lower
Direct-Atco - Alberta	$775	$2,979	-74%	lower
Union Gas - Ontario	$1,010	$2,366	-57%	lower
Enbridge Gas - Ontario	$875	$2,366	-63%	lower
Gaz Metro - Quebec	$1,543	$1,574	-2%	lower

Notes:
**Calculated BC Hydro rate based on the F2009-2010 RRA approved increase of 8.74% (inclusive of the applicable 1% rate rider)*

Annual Bills for natural gas and electric, for all territories, are based on an annual use rate of 95 GJ.

The efficiency of gas equipment is assumed to be 90% relative to 100% for electricity to determine equivalent electricity. Lower gas efficiency appliances would result in lower gas price advantages than indicated above.

The annual electric rates do not include the fixed monthly charges since it is assumed that a household already pays the basic electric charge for non-heating use.

All rates are as at April 1, 2009.

All rates are exclusive of applicable franchise fees and/or taxes (with the exception of the Carbon Tax). Interior BC community customers pay a franchise fee of approximately 3%, which would reduce the indicated price advantage of gas by a like amount.

All annual bills are best estimates based on the information available from each utility.

c) Forward Looking Operating Cost Advantage of Natural Gas likely to Decline

The ability to remain competitive to the price of electricity has become increasingly difficult, particularly over the last few years with increased natural gas prices and price volatility as well as the recent and growing burden of the carbon tax.

Near-term economic realities have improved the competitiveness of natural gas. Market prices are currently depressed due to declining industrial demand, high storage balances and weaker crude oil prices.

Yet, it is long-term factors that will have a greater influence on prices and volatility in years ahead. Such factors suggest that the competitiveness of natural gas will continue to erode. These long-term factors include declining Western Canadian Sedimentary Basin natural gas production, higher finding and development costs, increasing demand for power and air conditioning produced from natural gas outside of B.C., and the potential for active hurricane seasons affecting the Gulf of Mexico producing region. Furthermore, future economic recovery and the associated increase in demand combined with the reduction in natural gas production forecasted in 2009 could add to future market price volatility and potentially higher gas prices. While the gap between forecasted electricity rates and the current natural gas forward curve has widened in the short term, this may well be short lived given the volatility in the North American energy markets and the fact that the actual costs of finding and developing new sources of natural gas exceeds current market prices.[62]

The following graphs (Figure A-5 and Figure A-6) illustrate the recent volatility in natural gas commodity prices compared to the commodity component of the electric equivalent.

[62] As of June 9, 2009 forward natural gas prices at Sumas are $2.90 US/MMbtu for July/2009 and $5.80 US/MMbtu for the winter 2009/2010. These prices are below the average well supply cost of northeast BC shale production which is $6.80 US/mcf .

Figure A-5: AECO[63] Prices vs. Electric Equivalent Commodity Component

Current Prices as of May 11, 2009

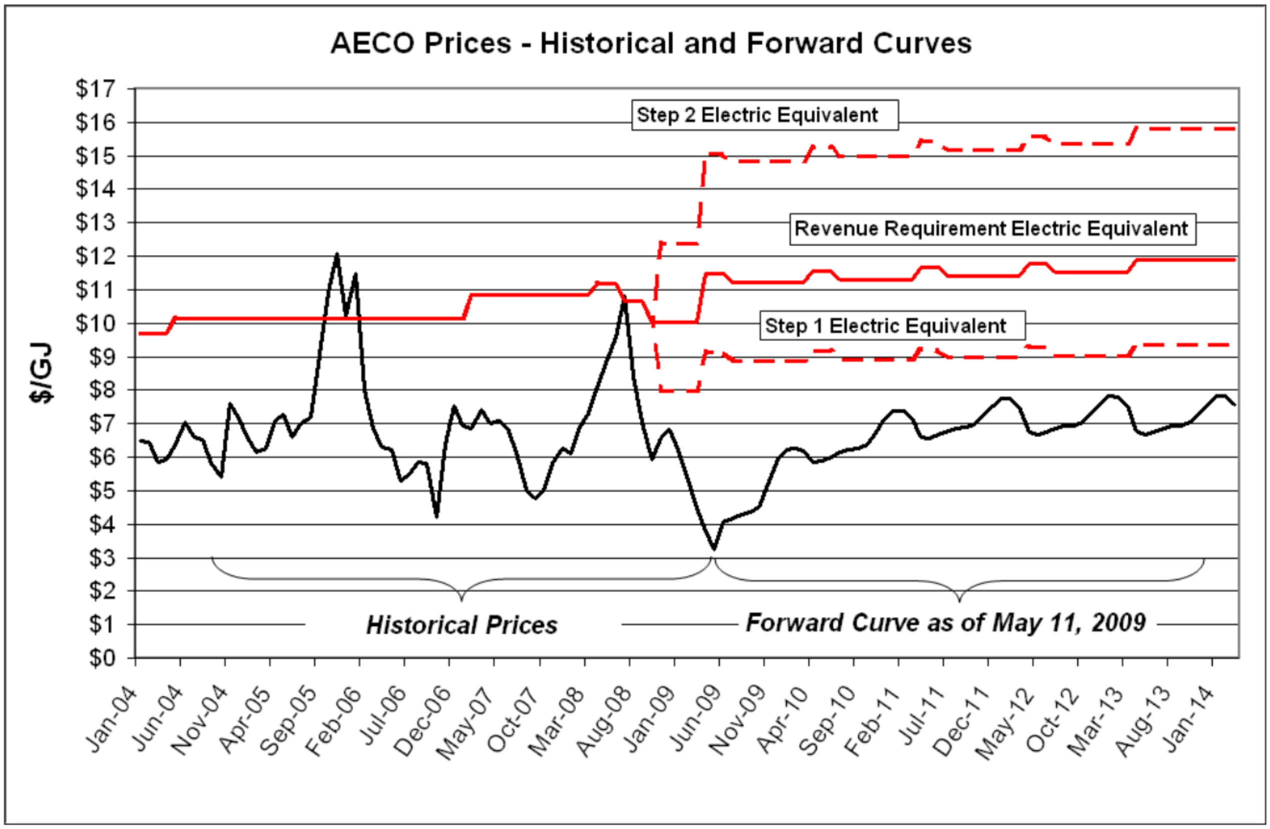


Figure A-5 indicates that at the current gas commodity price, and the current forecast gas commodity prices (forward curve), TGI has a competitive advantage against electricity on an operating cost basis over the next five years. However, the comparison in prices is absent any consideration of the required recovery of the upfront capital cost difference between a natural gas heated home and a home heated by electricity.

[63] AECO - The historical name of a virtual trading hub on the NGX system, located in the province of Alberta, Canada. Now known as the Nova Inventory Transfer (NIT) system operated by Trans Canada Pipelines Limited.

Figure A-6: AECO Prices vs. Electric Equivalent Commodity Component

Prices as of July 2, 2008

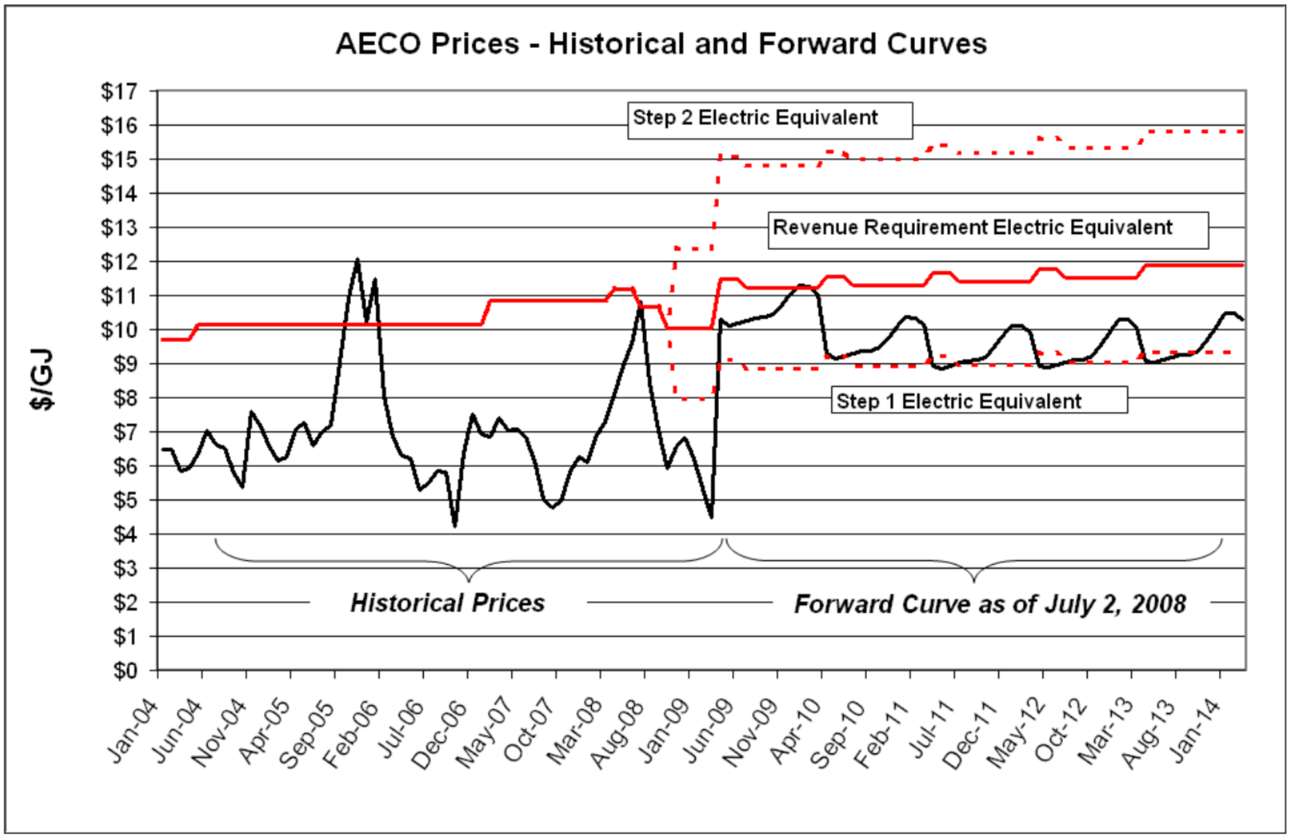


Figure A-6 provides an indication of the volatility of natural gas commodity prices. The forward curve on July 2, 2008 was very different from and substantially higher than, the current forward curve. This graph illustrates the nature of the highly volatile natural gas marketplace in which Terasen Gas operates.

As Figure A-5 indicates TGI has a competitive advantage against electricity on an operating cost basis over the next five years using the current forward curve (as of May 11, 2009). What is not apparent from Figure A-5 is that TGI requires a significant operating cost advantage to overcome the upfront capital cost differential for a natural gas versus an electrically heated home.

Figure A-7 shows the annual energy cost differential between a natural gas heated home and an electrically heated home must be more than $500 per year or $10.31 per GJ over the life of the asset, in order to offset the capital cost differential for natural gas equipment versus electric baseboards. These calculations are based on the assumptions outlined in Figure A-7.

Figure A-7: Payback on Capital Costs Difference for a Natural Gas Heated Home[64]

Payback of Capital Costs (New Construction)

Space Heating Requirement Only
New Construction of home in Lower Mainland (2500 square feet in size)

Capital Costs for High Efficent Furnace (90%) and ducting/installations	$7,000.00
Capital Cost for Electric Baseboards	($2,500.00)
Difference in up front capital costs	$4,500.00
Interest Rate	0.06
Measureable Life of Furnace (years)	18
Amount that has to be recovered in operating cost annually to payoff difference in capital cost	$415.60
Add in furnace maintence costs per year	$100.00
Total ($)	**$515.60**
Energy consumptions for natural gas space heating (GJ's)	50
Difference in cost that needs to exist between natural gas heated home and electricity heated home in $/GJ over 18 years	**$10.31**

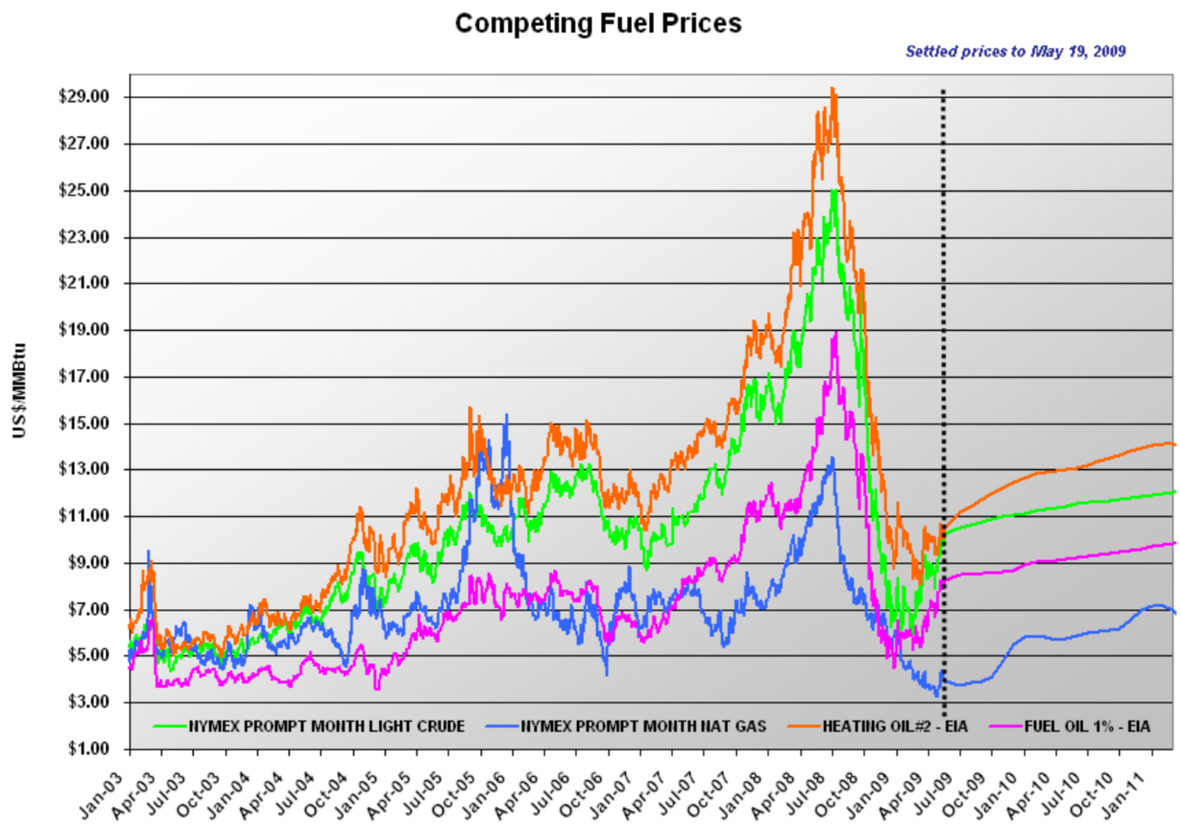
When the capital cost differential of $10.31 per GJ is added to the numbers outlined in Figure A-5, natural gas for space heating applications is not competitive relative to any of the electric rates outlined in Figure A-5, even the Step 2 RIB rate. The disparity in the overall competitiveness of natural gas taking into account upfront capital costs is very concerning given that natural gas commodity prices are lower today than in recent years. Prices are actually below the costs of finding and developing new natural gas supply resources, which suggests that natural gas prices are bound to increase in the future. This reality will have some impact on customers or developers that select energy forms or solutions based economic criteria. However, other customers segments may select natural gas as the solution to meet their energy needs based on a broader set of criteria such as: lifestyle benefits, net reductions in GHG's for the region and making efficient use of energy. Natural gas may also be used effectively in conjunction with other energy sources in, for instance, District Heating Systems.

[64] The 50 GJ used in this calculation relates to a new residential home located in lower mainland (2500 square feet). This 50 GJ is for space heating only and does not include other uses of natural gas in the home such as water heating or natural gas stoves. This 50 GJ is lower than the average Rate Schedule 1 use rate of 92.5 GJ for 2008 because the 92.5 GJ is related to the total demand not just the space heating load. Also it reflects a decrease for the higher efficiencies of the new home and new furnace as compared to the existing stock of houses and furnaces.

The operating cost differential between natural gas and electricity for space heating and other direct use applications may improve over time due to higher supply and infrastructure costs for BC Hydro. Recently, natural gas market prices have improved relative to other energy commodities (such as oil) in the North America marketplace (See Figure A-8), but face challenges in the BC marketplace due to the differing nature of how natural gas and electricity costs are set into rates.

As of May 19, 2009 natural gas has a forecasted cost advantage against other fuels used in heating application such as heating oil No.2 and fuel oil (1 per cent). In general, the ratio of oil to natural gas cost has improved from its 5 year historical average of 8.5:1, to a 5 year forecasted ratio of 10.4:1.

Figure A-8: Natural Gas Competiveness in to Other Energy Commodities is Improving on a Go Forward Basis



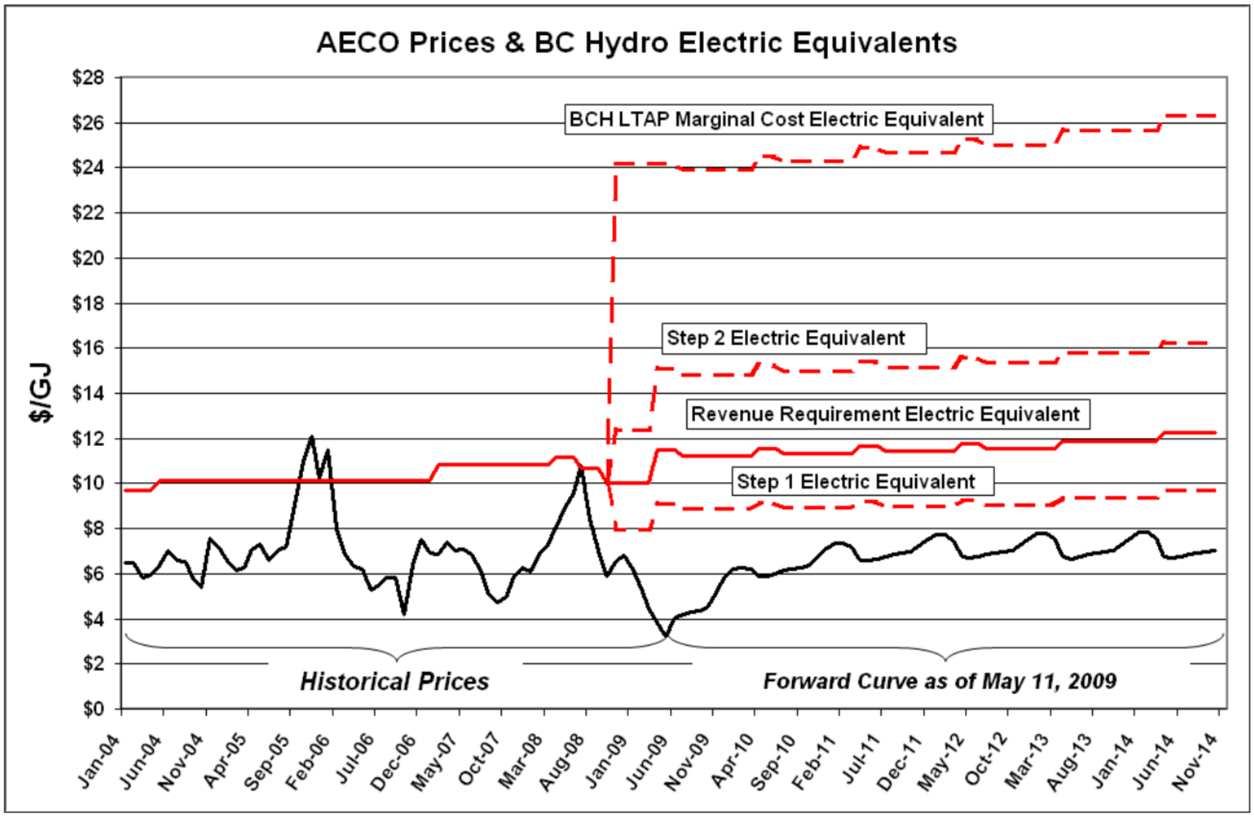
Due to such factors as low embedded (historical) electricity costs and the stated goal by the B.C. Government[65], the Terasen Gas operating environment is unique. As discussed above, this presents some challenges for Terasen Gas going forward. However, as Figure A-9 shows, if natural gas was

[65] See Appendix C-2 for a copy of Energy Plan 2007: A Vision for Clean Energy Leadership, page 4

competing against the marginal cost of electricity, then the natural gas competitive landscape would improve.

Figure A-9: AECO Prices vs. Electric Equivalent Commodity Component

Current Prices as of May 11, 2009 with BC Hydro Marginal Cost of Supply[66]



Absent this market reality, if true price signal cannot take place when alternative energy sources exist it is imperative that the appropriate rates and incentive mechanism, as well as consistent messaging, are in place to encourage the efficient use of all forms energy.[67] For these reasons, we need to invest in informing and educating policy makers, and communities looking to comply with the climate action challenges.

Securing reliable and cost effective gas supply resources is also an important part of trying to remain competitive against alternatives, namely electricity.

[66] BC Hydro marginal cost of electricity as outlined in the 2008 BC Hydro LTAP is $120/MW

[67] Efficient use of energy – as an example, direct use of natural gas in a new high efficiency natural gas fired furnace operating at 95% efficiency as compared to a modern combined cycle gas fired generator that operates at 50 to 55% efficiency.

On behalf on customers, the Gas Supply Department at TGI, works diligently in trying to meet the long standing objectives related to providing natural gas and propane commodity services to our sales customers.

Terasen Gas is proactive in regional resource developments and influencing the cost of available resources for the benefit of customers. This involves attending industry forums and conferences, being an active member of associations where Terasen Gas can promote its customers' interests, such as through the Northwest Gas Association ("NWGA") and Western Energy Institute ("WEI") and participating in the regulatory proceedings of regional pipeline companies in which Terasen Gas has an interest. Through this work, Terasen Gas has been able to understand how infrastructure is being utilized and developed in the region to meet the gas supply requirements of our customers and fulfill the objectives to provide reliable and cost effective supply resources to our customers.

d) Demand for Perceived "Green" Energy Represents an Additional Challenge

Direct use of natural gas must overcome two hurdles for the buyer to make a commitment to investing in natural gas equipment. One is the economic decision as discussed above. The second is related to the "green" perception of a product and how that product helps in meeting the climate change challenge.

Developers may install electric baseboards since this is the cheapest option from a capital cost perspective. There are also other developers who are looking to find ways to market new building stock as a "greener" alternative. In this type of building stock, builders are not only using electricity as already noted, but they are also looking to use geo-exchange systems, solar hot water systems, wood waste fired systems, and some or all of these fuels in district energy systems. Thus, natural gas may not be seen by some as the preferred option due to this growing trend towards greener alternatives.

Additionally, when Terasen Gas account managers meet with customers, we are increasingly asked about entire suites of energy solutions. Customer expectations are that the gas utility be the provider of information and advice on a range of energy solutions including gas, energy efficiency and alternative energy solutions. This is a marked change from the customer expectations that Terasen Gas experienced in the late 90's up until 2003. During this period, natural gas, primarily because of price and a lack of "green" energy policy, was the desired energy source for heating and comfort applications in homes and businesses.

In B.C., in contrast to other jurisdictions, natural gas is seen in the same light as other fossil fuels rather than being seen as a greener alternative. Customers cannot always be expected to understand the complicated nature of energy production and delivery and, as such, make decisions based upon limited information from media and other communication channels. Therefore, many customers see electricity, and alternative energy, as green and natural gas as “dirty”. In most other jurisdictions, moving customers from dirty fuels such as oil and coal fired electricity to natural gas end use or generation is seen as a greener alternative and part of the solution to reducing overall emissions. As we have discussed in other filings[68], natural gas, when used in end-use applications can result in lower GHG emissions and lower total energy use in the region by displacing electricity that is generated from fossil fuel. However, this message is particularly difficult to convey to customers and can result in decisions that, in effect, increase emissions from a regional perspective. An example is developers building and selling houses with electricity as a “green” house. Customers who do not know the complexities of energy will not have a reference point to dispute this selling methodology. Therefore, customers believe that electricity, due to hydro generation, is green is only enhanced by the activities and selling tactics of developers.

As a competitive “green” alternative to natural gas used for water heating, developers of multi-family units may consider solar energy to help meet the needs of their customers. For example, a solar-thermal project in a 40 unit multi-family residential development could provide hot water to the complex for a levelized cost of $9.47/GJ.[69] Such a system would not entirely replace a traditional hot water system, but rather would be expected to provide about 30 per cent of the customer’s hot water, reducing natural gas consumption and lowering carbon emissions as a result.[70] This example represents a relatively simple, low cost solution to the traditional hot water system that may have been provided solely by natural gas in the past.

e) Summary

In conclusion, the gradual erosion of the natural gas cost advantage in B.C. versus electricity impacts Terasen Gas’ growth in new customer additions, and also impacts throughput levels of existing customers. Increases in natural gas prices incent customers to reduce their energy consumption or look for cheaper alternatives to meet their energy needs. This issue is compounded by the climate change realities and how it will change customers’ perception of natural gas. In all cases the result is reduced consumption levels on the natural gas system which negatively impacts existing customer’s rates, all else being equal.

[68] BC Hydro 2008 LTAP – Terasen Utilities Final Submission – April 27, 2009
[69] See Appendix C-27 for a copy of Alternative Energy System Cost of Service
[70] See Appendix C-27 for a copy of Alternative Energy System Cost of Service

If true price signal cannot take place when alternative energy sources exist it is imperative that the appropriate rates and incentive mechanisms, as well as consistent messaging, are in place to encourage the efficient use of all forms of energy. For these reasons, we need to invest in informing and educating policy makers, and communities looking to comply with the climate action challenges and we need to invest in the assets and technologies that make these changes possible.

To meet these challenges Terasen Gas believes that the business needs to evolve.

4. BC Economic Outlook and Demographic Challenges

There have been significant changes in global, regional, and local economic conditions since the last Revenue Requirement Application was filed in 2003. These changes have meaningful implications for Terasen Gas' customers. It will impact their ability to pay for energy, impair their ability to make investments in energy conservation measures, lower customer additions and reduced customer demand for energy consumption. In addition to this economic downturn, Terasen Gas faces demographic challenges as do other employers across the country. We must develop different strategies to manage these risks to ensure that we can continue to meet the needs of our customers.

This section looks closely at the changing economic situation in B.C. by looking at:

- B.C.'s Economic Outlook for 2009-2011: Turbulent Times
- A Looming Demographic Challenge

a) B.C.'s Economic Outlook for 2009-2011: Turbulent Times

Generally, during the period of 2003 to 2007, the Canadian economy as a whole was performing well. Specifically the B.C. economy was booming and experienced solid economic growth. However, in 2008 the economy as a whole went into a decline. The B.C. economy was no exception to this trend, and experienced an economic downturn as a result of the US housing market correction and subprime mortgage crises that burst the US economic bubble and triggered a global recession. By the end of 2008, B.C. went through a decline in economic growth, higher unemployment rates, and lower housing starts, all of which have generated concern for how the B.C. economy may perform in the coming years. For further details of the Canadian and B.C. economic conditions for the period from 2003 to 2008 please see Appendix C-28: Economic Review 2003-2008.

The US-led global recession not only makes the future of economic conditions uncertain, but it is anticipated that the economic turmoil will require quite some time before a complete recovery is obtained. Although the recession in the B.C. economy is significantly less pronounced as compared to the US recession and the experience of some other Canadian provinces, risks to B.C.'s economic outlook include a prolonged period of low economic growth, further weakening of domestic demand, and further commodity price volatility.[71] Despite the fact that most economic indicators suggest that global economic conditions may remain turbulent for some time, B.C. is relatively well positioned to weather this storm. There have been signs of economic recovery in recent months with strengthened Canadian dollar[72] and improving commodity prices.[73] As has been experienced in the past, appreciation of the Canadian dollar will likely impact B.C. exports. However, proof that B.C.'s economy is doing better can be seen by employment gains as a result of 17,000 new jobs in the province[74] and urban housing starts[75] gains of 1 per cent in B.C. in April 2009, as compared to other provinces which saw a continued decline.

The following table summarizes the forecast changes in the economy based on the leading economic indicators from 2009 to 2011. The forecasts produced below reflect the best available information at the time of filing.

71 See Appendix C-29 for a copy of B.C. Fiscal Plan 2009
72 See Appendix C-30 for a copy of Loonie's rise dampens rebound
73 See Appendix C-31 for a copy of Canada Stocks – TSX poised to rise on commodity strength
74 See Appendix C-32 for a copy of B.C. gains 17,000 new jobs as Metro Vancouver unemployment drops
75 See Appendix C-33 for a copy of April Housing Starts

Table A-1: B.C. Economic Outlook Not as Bleak as Other Jurisdictions

	2009	2010	2011
Real GDP (per cent change)			
BC[76]	-0.9	2.4	2.6
ON[77]	-2.5	2.3	3.3
AB[78]	-2.0	1.8	3.0
Unemployment rate (per cent)			
BC[79]	6.2	6.0	5.7
ON[80]	8.8	8.9	8.2
AB[81]	5.8	6.5	6.2
Housing starts (per cent change)			
BC[82]	-34	-9	3
ON[83]	-33.4	10	18.2
AB[84]	-23.5	8.1	1.2

As demonstrated in Table A-1 forecast of B.C.'s economic conditions are not as bleak as other jurisdictions such as Ontario and Alberta. Alberta, which has an economy driven by the energy sector and Ontario with strong ties to the US economy are expected to experience a greater downturn in economic activity as compared to B.C. For instance, B.C. is expected to have lower real GDP decline in 2009 and higher economic growth in 2010, when compared to Ontario and Alberta. Moreover, B.C.'s unemployment rate is expected to remain lower than Ontario, where the majority of layoffs have been taking place.

76 See Appendix C-34 for a copy of British Columbia Budget 2009
77 See Appendix C-35 for a copy of Ontario Budget 2009
78 See Appendix C-36 for a copy of Alberta Budget 2009
79 See Appendix C-34 for a copy of British Columbia 2009
80 See Appendix C-35 for a copy of Ontario Budget 2009
81 See Appendix C-36 for a copy of Alberta Budget 2009
82 See Appendix C-37 for a copy of CMHC Housing Market Outlook - BC Region Highlights First Quarter 2009
83 See Appendix C-35 for a copy of Ontario Budget 2009
84 See Appendix C-36 for a copy of Alberta Budget 2009

It is expected that B.C. will post virtually no economic growth on a year-over-year basis in 2009 and many industrial sectors (largely forestry) will continue to be affected by the recession. In fact, B.C.'s real GDP is forecast to decline by 0.9 per cent this year, the weakest performance since 1982.[85]

Also, layoffs are expected to accelerate in many sectors, including construction, real estate and related services, financial services and retail. A total of 35,000 jobs were lost in B.C. in January 2009[86] followed by 14,000 layoffs in the month of February.[87, 88] The unemployment rate is expected to rise to an average of 6.2 per cent in 2009. This slower economic growth and rising unemployment rate will weaken demand for homeownership and thus housing starts are expected to decline by 34 per cent in 2009.[89] This economic reality will have an impact on some customers' ability to pay for basic needs, such as home heating.

In 2010, it is expected that B.C. will reap significant economic benefits and growth from hosting the 2010 Olympic and Paralympic Winter Games. A return to economic growth is anticipated with the province's real GDP forecast to rise by 2.4 per cent.[90] With the expected positive trend for 2010, B.C.'s economic well-being should show slight improvement and the unemployment rate is expected to decrease to an estimated rate of 6.0 per cent. Despite the expected economic growth, housing starts will likely continue to decline by 9 per cent in 2010.

In 2011, it is expected that the B.C. economy will continue recovery at a moderate pace, whereby real GDP is expected to grow by 2.6 per cent. Unemployment is expected to decline in 2011 as the first wave of the baby boomers[91] will reach 65, potentially expanding the number of opportunities in the labour market. Housing starts will likely recover from the declining rates of the last couple of years to 3 per cent in 2011.

Lower economic growth, higher unemployment rates, and declining housing starts indicate that the economic turmoil will most likely impact Terasen Gas by lowering customer additions and reducing customer demand for energy consumption.

---

85 See Appendix C-38 for a copy of RBC Economics March 2009
86 See Appendix C-39 for a copy of B.C. sheds 68000 full-time jobs in January
87 See Appendix C-40 for a copy of Unemployment rate climbs to 6.7% in B.C.
88 See Appendix C-41 for a copy of B.C. economy to decline 1.5 per cent in 2009
89 See Appendix C-37 for a copy of CMHC Housing Market Outlook - BC Region Highlights First Quarter 2009
90 See Appendix C-34 for a copy of British Columbia Budget 2009
91 Baby Boomers is the name given to the generation of North Americans who were born in a "baby boom" following World War II. The Boomers were born between 1944 and 1964. The oldest wave of the Baby Boomers is currently considering retirement options and looking at ways to make their elder years meaningful.

It is critical to assess the economic conditions for the next three years and the impact of it on the business of Terasen Gas in order to ensure that forecasted costs and revenues in this Application are prudent and necessary to meet the evolving needs of the Company's customers.

Please see Part III, Section C, Tab 4 for more details relating to the economic factors that help determine customers' throughput and new customer additions.

b) A Looming Demographic Challenge

TGI must continue to invest in managing the looming demographic challenge to ensure that we can continue to meet customer needs.

Shifting workforce demographics are a well-known global reality and a major source of concern for governments and businesses alike. Many economists have been predicting for some time that the looming retirement bubble of baby boomers will create serious labour shortages, particularly in the skilled trades and professional occupations. The situation is made even worse by the fact that Canada has been experiencing declining fertility rates and not enough Canadians have been born in the last several years to replace those workers who will reach retirement age in the coming two decades. In an October 2008 report, the Conference Board of Canada noted:

> *"Given low fertility rates in Canada and increased competition for skilled immigrants, the pool of younger workers available to replace retiring baby boomers will not be sufficient to meet employers' future staffing needs."*[92]

Similarly, the Business Council of British Columbia has acknowledged that the challenges of dealing with an aging workforce will be a major concern for many companies:

> *"With a large portion of their workforce approaching the traditional age of retirement, companies are going to have to pay much more attention to succession planning and recruitment than in the past."*[93]

The recent elimination of mandatory retirement in British Columbia represents one strategy aimed at mitigating the risks of an aging workforce and the looming shortage of skilled workers. In 2007 the provinces of British Columbia and Alberta adopted another strategy by signing the Trade, Investment

[92] See Appendix C-42 for a copy of Harnessing the Power: Recruiting, Engaging and Retaining Mature Workers

[93] See Appendix C-43 for a copy of The Current Challenges Facing Human Resources and Labour Relations Professionals

and Labour Mobility Agreement ("TILMA") aimed at improving access to skilled labour through automatic inter-provincial recognition of various professions and skilled trades such as engineers, electricians, mechanics, and others. TILMA subsequently paved the way for a new national agreement on labour mobility, the Agreement on Internal Trade ("AIT") signed by the provinces on December 5, 2008. This agreement contains two key amendments – a revised labour mobility chapter and a revised Dispute Resolution Mechanism – and is considered to mark a significant milestone towards eliminating internal trade barriers and enhancing labour mobility across Canada. Specific changes to the AIT as it relates to labour mobility are summarized as follows:

> **9th Protocol of Amendment: Labour Mobility (Chapter 7)**
> *"Canadians should be able to work in their chosen occupations anywhere in Canada. The revised labour Mobility Chapter of the AIT will provide that any worker certified for an occupation by a regulatory authority of one province or territory is to be certified for that occupation by all others.*
>
> *Any exception to full labour market mobility will have to be clearly identified and justified as necessary to meet a legitimate objective, such as the protection of public health or safety.*
>
> *The Committee of Internal trade has approved, in principle, that all Canadians will enjoy full labour mobility by April 1, 2009."*[94]

In a news release issued March 12, 2009, the Government of British Columbia announced its endorsement of the new AIT as follows:

> *"The new AIT removes a long-standing barrier, and further enables B.C. to attract, and quickly employ, the skilled trades and professions needed in many sectors – especially important as retirements over the next 10 years are forecast to exceed the total number of students currently in the B.C. post-secondary system."*[95]

The Business Council of B.C. has forecast over a million job vacancies by 2018 while only 650,000 young people will move through the province's K-12 school system over the same period. This is expected to result in a "shortfall" of 350,000 prospective workers as measured against the expected number of job openings even if all the K-12 graduates remained in B.C.[96]

---

[94] See Appendix C-44 for a copy of Agreement on Internal Trade
[95] See Appendix C-45 for a copy of B.C. Leads Canada with Labour Mobility Bill
[96] See Appendix C-46 for a copy of The Role of Temporary Foreign Workers in Easing Labour Shortages

Professional associations have also expressed concern about attrition in their membership. In October, 2007, the Applied Science Technologists and Technicians of British Columbia ("ASTTBC") held a Roundtable on Technology Skills Shortages with stakeholders representing all sectors to engage in a discussion on the critical shortage of skilled workers in British Columbia. One of the actions coming out of the Roundtable was:

> *"…the formation of a Technology Education & Careers Council ("TECC") to provide strategic leadership and advocacy in advancing the importance of technology careers and education in B.C., serve as a catalyst for action and articulate industry policy with governments and educators."*[97]

TECC members are drawn from industry and stakeholder leaders, and includes the Vice President of Human Resources and Operations Governance at Terasen Gas. The mandate of the TECC is to oversee and champion a Technology Skills Action Plan to proactively address the following concerns:

- Almost half of the current technologists and technicians will retire as the oldest baby boomers start to leave the workforce.
- The B.C. and Canadian economies are forecast to grow steadily, led by the high tech sector and technology-based processes.
- In B.C. the 2010 Olympic and Paralympic Winter Games, construction and real estate development, mining and resource projects, and the growth of the province's cities and population, have and will create a huge surge in demand for trained and qualified workers.
- By 2010, there is projected to be a 70 per cent shortfall in the supply of needed supervisors, managers and contractors in trades and technologies.
- In the meantime, B.C. post-secondary institutions are closing down and reducing spaces in technology programs, and few opportunities are provided for technology workers to complete necessary continuing education and lifelong learning.

The demographic challenge facing employers across the country is very real. Businesses must also develop different strategies to manage these risks, and for Terasen Gas the demographic challenge is more daunting than most. From a Human Resources perspective, our Application will outline the magnitude of this challenge, identify what HR strategies have already been undertaken and what additional actions will be required to effectively manage the risks over the next several years (see Part III, Section B, Tab 2).

[97] See Appendix C-47 for a copy of Roundtable on Technology Skills Shortage II

c) Summary to B.C. Economic Outlook and Demographic Challenges

In general, the economic conditions in B.C. for the time period 2009-2011 have worsened compared to most of the time covered by the PBR Period. Lower economic growth, higher unemployment rates, and declining housing starts indicate that the economic turmoil will most likely impact Terasen Gas' customers. It will impact their ability to pay for energy, impair their ability to make investments in energy conservation measures, lower customer additions and reduce customer demand for energy consumption.

In addition to this economic downturn, Terasen Gas faces demographic challenges as do other employers across the country. Businesses must develop different strategies to manage these risks, and for Terasen Gas the demographic challenge is more daunting than most in meeting customer evolving needs. See Part III, Section B, Tab 2 for how Terasen Gas will address this demographic issue.

5. Accounting Standards and Related Guidance are in Flux

Accounting standards and related guidance are continually evolving to anticipate and react to changes in the requirements and expectations of financial statement users. These requirements and expectations often result from the same changes to legislation and to the external environment that were discussed above. Pending changes in accounting standards are the single greatest cost driver of the rate increase sought in 2010 and 2011.

Canadian utilities are required to comply with accounting standards known as Canadian Generally Accepted Accounting Standards ("GAAP"). The guidance contained in these standards has been reflected in the determination of rates. As GAAP has evolved, the resulting changes have been incorporated into revenue requirements filings with Canadian regulatory bodies.

In recent years, there has been an accelerated pace of change in Canadian GAAP, and the resulting standards have become increasingly more complex. Of particular note are changing standards on financial instruments and hedging, corporate income taxes, asset retirement obligations, variable interest entities, asset impairment, stock based compensation, employee future benefits, comprehensive income, goodwill and intangible assets, inventories, and rate regulated entities.

Canadian accounting standards are now entering a time of unprecedented change, as the standards that are applied in the creation of financial statements, and also incorporated in the determination of rates, change from Canadian GAAP to IFRS. Canadian utilities will be required to comply with IFRS for financial reporting periods commencing on January 1, 2011, with comparative figures for 2010 restated to be in compliance with IFRS. Canadian utilities must be ready and able to reflect the 2010 effects of IFRS in both their financial statements and their revenue requirements filings.

Changes in accounting policies do not change the amount of total costs to be recovered from ratepayers, but changing standards do affect the timing of when those costs are recovered. Rates may rise in the short term, but this initial rise in rates will be offset by lower rates in the future.

Further details on the specific changes required to comply with IFRS and the implications of those changes on Terasen Gas' revenue requirements are contained in Part III, Section C, Tab 11.

Summary for the External Situation Context

The factors outlined in this section present a picture of increasing demands of, and pressure on, our base business, while also presenting opportunities to expand and evolve our service offerings to meet the challenges of energy efficiency and climate change policies. Terasen Gas is committed to creating the long-term solutions and business models that will allow its customers and communities to address these challenges. The Application reflects the imperative to invest in our ability to serve customers and expand our ability to offer comprehensive energy solutions.

Introduction

Historically, electricity, natural gas, and propane have been the main sources of energy consumed in end use applications in BC. For example, they were responsible for meeting over eighty five percent of space heating and ninety eight percent of water heating in the residential sector in 2008. Heating fuel is responsible for around five percent of the heating needs in BC[1]. These energy sources have overlapping service territories, which has presented customers with different options to meet their energy needs. TES will be another energy solution that customers will consider when making energy choices overtime. The contribution of electricity, natural gas, and propane to the provision of energy in BC is discussed below.

Electricity

Electricity is the most versatile energy form and can be used for a variety of purposes in homes, businesses and industry. Electricity is a high value energy form that has already been converted to useable energy from another primary energy source such as hydro, fossil fuels, nuclear, wind or the sun. It can be used for lighting, appliances, televisions, computers and electronic equipment, electric motors, as well as space heating, water heating, and air conditioning. Given BC's moderate climate, particularly in the coastal areas, there are relatively few residential buildings that use air conditioning. Electricity is mainly used for lighting and other appliances (and optional cooling), and for heating. It is noted that the use of electricity to meet space heating needs in the residential sector has increased from 18% in 1990 to 28% in 2008[2] and this trend is likely to continue in view of government energy objectives and policies.

Most of BC's electricity has been generated from clean sources. However, given that the province consumes more electricity than we generate, it has seen an increased need to import electricity (which is not all clean) in order to meet energy demands of BC. There has been a proliferation in the number of uses for electricity (appliances and consumer electronics mainly) and even with efficiency gains in large appliances like refrigerators and dishwashers the load from new uses adds more demand, and electricity use per customer continues to increase.

In British Columbia, electricity is provided primarily by two regulated public utilities - BC Hydro and FortisBC Inc. – together with a number of municipal utilities.

[1] Natural Resources Canada
[2] Ibid

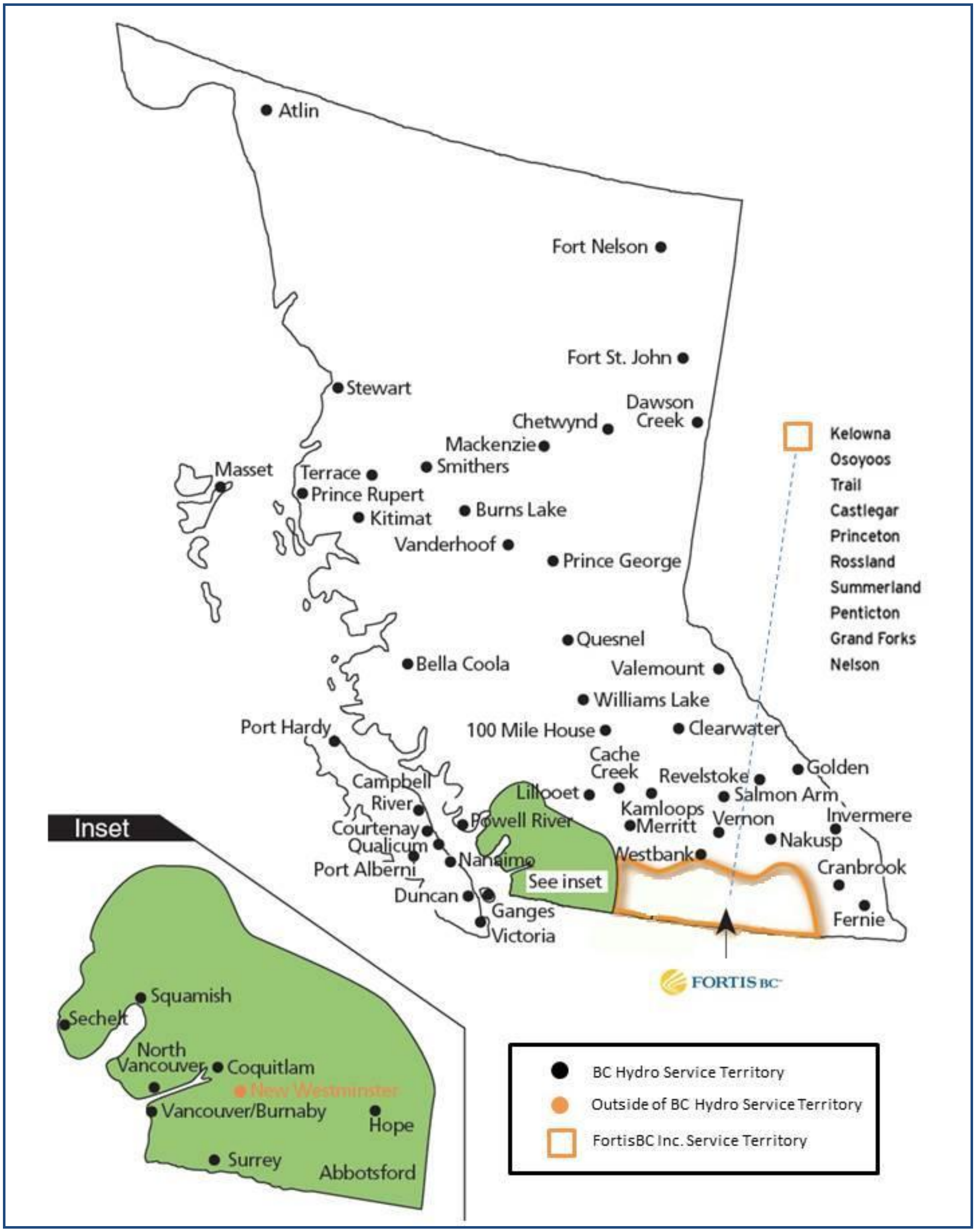
BC Hydro is a commercial Crown corporation owned by the Province of British Columbia, serving approximately 95 percent of the Province's population and approximately 1.8 million customers[3]. BC Hydro generates annually around 43,000 GWhrs[4] of electricity and provides electricity for one municipal utility in the Lower Mainland, the City of New Westminster. BC Hydro also provides electricity service to electricity resellers under a number of arrangements. The resellers in turn serve other end use electricity customers. Examples of electricity resellers include UBC Utilities, the Vancouver International Airport Authority and Corix Multi-Utility Services at Sun Rivers and Sonoma Pines.

FortisBC Inc. serves approximately 111,500 electric customers in the south central part of the province including Kelowna, Osoyoos, Trail, Castlegar, Princeton and Rossland. It also serves approximately 48,500 electric customers through the wholesale supply of power to municipal distributors in the communities of Kelowna, Summerland, Penticton, Grand Forks and Nelson.

The map of British Columbia in Figure 1 below provides an approximation of the service areas of the electric utilities in British Columbia.

[3] BC Hydro 2011 Annual Report
[4] Ibid

Figure 1: Electric Utility Service Areas in BC



Historically, about 20 percent of BC Hydro residential customers use electricity for space heating and 35 percent use electricity for water heating[5]. With trends toward more multi-family housing and "green" energy solutions the likelihood is that, without alternative thermal energy taking up some of the demand, electricity would occupy a larger share of the space heating / water heating market going forward. Providing thermal energy service for space and water heating is an alternative solution which helps to relieve rate pressure on the electricity system.

Natural Gas and Propane

Natural gas, and to a lesser extent propane, provide the conventional energy alternative to electricity, and are the "cleanest" fossil fuels for space and water heating and cooling. Natural gas has many different applications including heating and cooling, direct use applications, electricity generation, and even transportation solutions. In BC, natural gas is provided, for the most part, in the same geographic footprint as electricity, making it possible for most consumers in the province to choose which energy source they want to use. The use of natural gas for space heating in the residential sector has remained almost constant at around 56 percent for many recent years despite the growth in the residential dwellings[6]. The growth in multi family dwellings, where natural gas has a penetration rate of less than 20 percent, and government energy objectives and policies, are likely to negatively affect the market share of natural gas in this sector going forward.

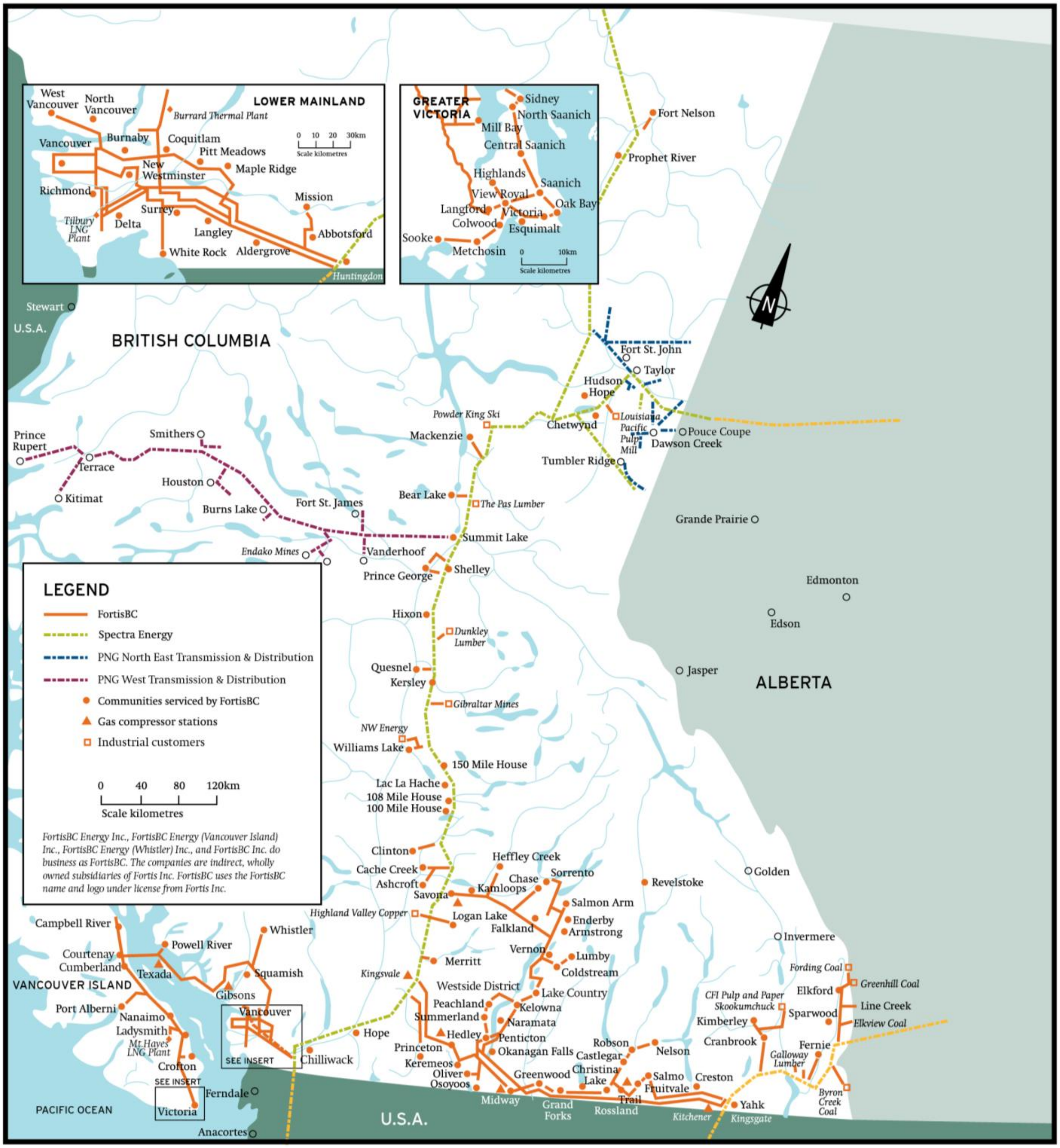
Piped propane is provided in certain areas within the same footprint as electricity in BC. Bottled propane service is available in many remote or rural areas that do not get either natural gas or piped propane service.

In British Columbia, natural gas and piped propane service are provided primarily by FortisBC Energy Utilities ("the FEU") and Pacific Northern Gas ("PNG"). The FEU serve approximately 948,970 natural gas and propane residential, commercial and industrial customers in 125 British Columbia communities. PNG serves approximately 39,500 residential, commercial and industrial customers. Figure 2 shows the natural gas operating areas on a map of BC.

[5] FEU Final Submission BC Hydro, 2008 LTAP

[6] Natural Resources Canada

Figure 2: Natural Gas Service Areas in BC



As the above map depicts, the FEU service territory includes the Lower Mainland, Inland, Columbia, Whistler, Revelstoke, Fort Nelson and Vancouver Island regions, and the PNG has two systems, namely PNG West and PNG North East. PNG West covers the area between Summit Lake and Prince Rupert while PNG North East includes Fort St John, Taylor, Dawson and Tumbler Ridge.

Other Energy Forms

Consumers in BC can also use a number of other energy sources to meet their thermal energy needs. For instance, bottled propane service is available in many parts of the Province and tends to be used more commonly in rural and remote areas that are not economic to connect to the natural gas grid or the piped propane systems. There are also areas in the Province in which the use of heating oil for thermal energy requirements is still prevalent. In rural and remote areas wood-burning is also used to meet thermal energy needs.

Central Heat is a good example of a further type of thermal energy utility in BC. Central Heat provides steam in the downtown Vancouver area, within the same geographic footprint as electricity and natural gas, making it possible for consumers in downtown Vancouver to choose which of the three energy sources they want to use for heating.

Conclusion

In British Columbia, electricity, natural gas, and other thermal energy forms have, and have long had, overlapping service territories. As a result, customers in British Columbia have long had different options to meet their energy needs. TES will be another energy solution that customers will be able to consider when making energy choices in British Columbia.

<u>Appendix B</u>

Stakeholder Communication

1. Letters of Support for Biomethane
2. Letters of Support for Natural Gas Vehicles
3. Energy Efficiency and Conservation Stakeholder Group

CENTRAL HEAT DISTRIBUTION LIMITED
VANCOUVER DISTRICT ENERGY UTILITY
Suite 1, 720 Beatty Street, Vancouver, BC V6B 2M1
Tel 604-688-9584 Fax 604-688-2213 E-mail chdl@telus.net

May 10, 2010

Terasen Gas Inc.,
16705 Fraser Highway,
SURREY, B.C.
V4N 0E8

Attention: Mr. David Bennett,
Director, Resource Planning and Market Development

Dear Mr. Bennett:

Re: Letter of Intent - Biomethane Purchase

This letter is to confirm that Central Heat wishes to purchase 10,000 GJ per year of biomethane from Terasen Gas if approved by the BC Utilities Commission and is willing to sign the appropriate Service Agreement to do so at the anticipated cost of biomethane of $10-$12 per GJ.

We support Terasen Gas in its effort to provide alternative energy solutions, such as biomethane, and we want to play a part in helping this source of renewable energy become more widely available.

Methane gas, otherwise released to atmosphere, has over twenty times the heat retention property of carbon dioxide, thus greenhouse gases are reduced significantly when it is blended with natural gas.

We see this project as the first of many towards building a diverse clean energy sector for British Columbia. Congratulations to Terasen Gas for showing the leadership in make this opportunity a reality.

We look forward to working with Terasen Gas to make this project a success.

Yours truly,

CENTRAL HEAT DISTRIBUTION LIMITED

John S. Barnes,
President and General Manager

JSB/ye

cc: Ms. Janet Devaney, Terasen Gas Inc.

BC AGRICULTURAL RESEARCH & DEVELOPMENT CORPORATION
ardcorp

Renewable Agri-energy Initiative (RAI),
Wednesday, Aril 21st 2010

Subject: Terasen Gas' application to the B.C. Utilities Commission (BCUC) to charge a voluntary premium price for biomethane.

This letter is to show the Renewable Agri-energy Initiative's (RAI) conditional support for Terasen Gas' application to the B.C. Utilities Commission (BCUC) to charge a voluntary premium price for biomethane.

The Renewable Agri-energy Initiative (RAI) was created to heighten awareness of renewable agri-energy and create an enabling environment for renewable agri-energy production to the benefit of B.C.'s agricultural sector. A renewable agri-energy technology identified by the RAI that will benefit both B.C.'s agricultural sector and the province of B.C. as a whole is anaerobic digestion.

Currently, however, the adoption of anaerobic digestion technology is largely economically unfeasible in B.C. due to the Province's electricity and natural gas prices. The RAI is therefore supportive of Terasen Gas' application to the B.C. Utilities Commission (BCUC) to charge a voluntary premium price for biomethane from anaerobic digestion, as it feels this premium will enable anaerobic digestion to become economically feasible in B.C.

The RAI's support for Terasen Gas' application is conditional on the fact that this voluntary premium price will allow for Terasen Gas' rate of return and enable anaerobic digestion owners to receive a fair and reasonable return on investment. Furthermore, this letter of support is for Terasen Gas' application to the BCUC to charge a voluntary premium price for biomethane. As such, this letter is in no way support for any individual anaerobic digestion projects.

By agreeing to Terasen Gas' application, the BCUC will be demonstrating vital leadership in enabling B.C.'s agricultural sector to adopt a technology that will benefit both B.C.'s agricultural sector and the province of B.C. as a whole.

Sincerely,

Mathew Dickson,
(Program Manager, Renewable Agri-energy Initiative).

#230 – 32160 South Fraser Way, Abbotsford, BC V2T 1W5
Phone 604.854.4483 Fax 604.854.4485
Toll Free 1.866.522.3447

BC Bioenergy Network
PARTNERING FOR A GREENER FUTURE

1501-700 West Pender Street
Pender Place I Business Building
Vancouver, BC Canada, V6C 1G8

April 19, 2010

Terasen Gas Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

Re: Support for Terasen Gas Renewable Biogas BCUC Application Filing

We are writing this letter to express full support for the Terasen Gas Inc. ("Terasen") filing to the British Columbia Utilities Commission ("BCUC") to bring renewable gas to residential gas customers in British Columbia.

About the BC Bioenergy Network

The BC Bioenergy Network ("BCBN") is a not for profit organization established in 2008 with $25 million from the BC government with the objective to grow a world-class bioenergy industry in BC. We are governed independently by a board of directors, who represent three industry associations (the Council of Forest Industries, the BC Agricultural Council and the BC Technology Industry Association), the University of British Columbia, and the Government of British Columbia (the Deputy Minister of the BC Ministry of Energy, Mines, and Petroleum Resources).

Our mandate is to:

- Maximize the value of BC's biomass resources;
- Develop mission-driven research, development and demonstration projects;
- Reduce GHG emissions;
- Network and partner in BC, Canada, and internationally to advance BC's bioenergy sector; and
- Lever funding to support BC focused bioenergy technology and applications.

Relationship with Terasen Gas

BC Bioenergy Network has been working actively with Terasen on renewable energy for over a year. On September 2009, BC Bioenergy Network signed a Memorandum of Understanding ("MOU") with Terasen to formalize efforts to work collaboratively on areas of mutual interest related to bioenergy development, including exchange of information, outreach and communications activities, and project development.

Biogas Benefits for British Columbians

Providing British Columbians with renewable alternative energies, like biogas, is part of the BC government's objectives and has been outlined in the BC Energy Plan, BC Bioenergy Strategy, and most recently in the March 2010 budget announcements. Renewable biogas can be obtained from municipal landfills, municipal wastewater or agricultural residues which are readily available here in BC, processed and upgraded to pipeline quality, and then injected into the natural gas distribution system. Biogas offers substantial benefits given it is carbon neutral, clean, renewable, and offers more price stability than natural gas. It utilizes wastes and turns them into a source of energy.

In 2008 the "*Feasibility Study – Biogas upgrading and grid injection in the Fraser Valley, British Columbia*", was completed for the BC Innovation Council, which indicated that "anaerobic digestion and biogas upgrading are common and mature technologies used extensively throughout Europe and the USA. In Canada, biogas production is starting to increase. This growth is primarily in Ontario due to favourable renewable energy feed-in tariff regime.

The study further notes that "results from a previous study in 2007, show that organic wastes generated in the lower mainland have the potential to produce and displace the equivalent of over 120 million cubic meter of natural gas per year, i.e. approximately 3.5% of the current lower mainland fossil natural gas consumption. This is equivalent to diesel consumed by 80,000 cars (100 million litres). Biomethane, gas from organic sources, can also be used to fuel compressed natural gas ("CNG") vehicles. Automotive application of biomethane has the potential to displace over 100 million litres of diesel and reduce greenhouse gas ("GHG") emissions by 335,000 tonnes per year. One of the additional advantages of producing biogas from methane sourced from either municipal landfills, wastewater or on-farm waste, is that it can deliver renewable natural gas at a price that can closely compete with fossil fuel when the carbon tax exemption ($1.50/GJ in 2012) and avoided pipeline transportation cost that natural gas from Alberta and northern BC incur are included."

BC Bioenergy Network Supports Terasen's First Investment in Municipal Biogas with a $200,000 Grant

The Columbia Shuswap Regional District ("CSRD") and Terasen are developing a landfill gas ("LFG") collection and upgrade system at the Salmon Arm Landfill. On March 31, 2010, the Board of BC Bioenergy Network approved a grant of $200,000, subject to contracting, to Terasen to be used toward the capital investment in the upgrading portion of the project, estimated at $1.35 million.

The proposed project will be the first in British Columbia to recover raw biogas from a landfill, upgrade the gas to pipeline quality for inclusion in the natural gas distribution infrastructure and potentially to use it as green transportation fuel. This will demonstrate a viable alternative to producing electricity from gas and is a key building block in Terasen's green gas offering to residential customers. This is an excellent fit with BC Bioenergy Network's mandate and provides leverage of its funds. Terasen has further agreed to designate the project as a BC Bioenergy Network Collaborative Demonstration and Development centre, furthering the dissemination of economic and environmental information to regional governments in BC, and assisting them to meet their BC Climate Action Accord goals. This centre is modeled after the successful Collaborative Demonstration and Development centre undertaken with the Regional District of Nanaimo and Cedar Road LFG Inc. on Vancouver Island in conjunction with the BC Bioenergy Network, where the landfill gas if being collected and then utilized to produce electricity.

Project benefits for the province include reduction of GHG emissions through the utilization of landfill gas and an offset associated with the displacement of traditional natural gas by natural gas consumers. BC Bioenergy Network is keen to see the installation of a biomethane compressed gas fuelling station to further generate GHG reductions to displace the utilization of fossil diesel fuels.

The Government of British Columbia has actively promoted its' commitment to supporting the development of clean technology companies while at the same time reducing greenhouse gases in the province. Terasen is demonstrating how a utility can show leadership in supporting government commitments by offering smart, efficient energy choices for its customers, creating local clean energy jobs from the sourcing and delivery of biogas, spurring investment in BC's clean energy sector, and demonstrating the viability of biogas as an energy source, including its potential use in the transportation sector as a clean renewable fuel alternative.

In conclusion, BC Bioenergy Network fully supports Terasen's application for both the green gas offering and the and the first two projects, Catalyst Power and Columbia Shuswap Regional District landfill and trusts that BCUC will also support this environmentally and economically beneficial approach to effective energy planning.

Yours sincerely,

Michael Weedon
Executive Director

5 - 4217 Glanford Avenue
Victoria, BC Canada V8Z 4B9
(250) 744-2720
info@bcsea.org

5 April 2010

Ms. Erica Hamilton
Secretary, BC Utilities Commission
Vancouver, BC

Dear Ms. Hamilton,

Re: Terasen Gas proposal to bring renewable biogas to residential customers

The BC Sustainable Energy Association is pleased to support the application it understands Terasen Gas will make to the Commission to bring renewable biogas to its residential customers.

Appropriately carried out and regulated, the use of renewable biogas would cause net reductions in greenhouse gas emissions in BC relative to business as usual. As such, it would contribute to meeting BC's legislated greenhouse gas reduction goals, and it would contribute to reducing BC's contribution to global climate change.

As well, it could increase the awareness among Terasen's customers of climate change and actions that may be taken to address it. This could lead to the beneficial effect of greater public engagement in reducing GHG emissions.

Sincerely,

Thomas Hackney, Vice-President for Policy

April 28, 2010

British Columbia Utilities Commission
Box 250, 900 Howe Street, Sixth Floor
Vancouver, B.C. V6Z 2N3

Dear Sir/Madam:

Re: Terasen Gas initiative to offer renewable biogas to residential gas customers in B.C.

It has been brought to our attention that Terasen Gas is seeking support to provide B.C. residential gas customers with the option of purchasing a 10% biogas blend at a premium price to natural gas.

Bullfrog Power supports this initiative to provide customers the choice of purchasing renewable energy options. Bullfrog Power was founded five years ago with the objective of providing a renewable electricity choice to Canadians interested in leading the change to renewable power. Currently, Bullfrog Power offers a renewable electricity choice in six provinces, as well as a solar hot water offering in Ontario. Our experience has been that a growing number of Canadians want clean energy choices, and are prepared to voluntarily pay a premium for 100% clean electricity. We believe that BC gas consumers would similarly welcome a renewable biogas choice. In order to make the biogas offering a success, it must be accompanied by comprehensive communication programs to educate consumers about renewable biogas and its environmental benefits, as Bullfrog has done for our renewable electricity and solar hot water offerings.

Bullfrog Power is supportive of the Terasen Gas biogas initiative and, if called upon, would be willing to participate with Terasen Gas in the successful deployment of renewable biogas market deployment, leveraging our unique expertise in renewable energy market development.

Yours truly,

Tom Heintzman
President

TH:lp

www.bullfrogpower.com

Bullfrog Power Inc. 119 Spadina Avenue, Suite 1000, Toronto, ON M5V 2L1 Canada tel 416.360.3464 fax 416.360.8385

ABBOTSFORD

Abbotsford Spirit of BC

Mayor
George W. Peary

Councillors
Les Barkman
Simon Gibson
Moe Gill
Lynne Harris
Dave F. Loewen
Bill MacGregor
Patricia Ross
John G. Smith

April 12, 2010
File: 5280-01

British Columbia Utilities Commission
Box 250, 900 Howe Street
Sixth Floor
Vancouver BC
V6Z 2N3

c/o

David Bennett, Director, Resource Planning & Market Development
Tersaen Gas Inc.
16705 Fraser Highway
Surrey, BC
V4N 0E8

Dears Sirs:

Re: Support of Terasen Biogas Initiative

The City of Abbotsford wishes to extend its endorsement for the Terasen Gas initiative to supply residential customers with renewable biogas. This proposal is laudable in that it addresses several key issues of concern in the City of Abbotsford.

Abbotsford is one of the most productive agricultural areas in all of Canada, and as such, agriculture provides the economic foundation upon which the community is most dependent. The high concentration of dairy and poultry operations in Abbotsford brings with it the problematic issue of agricultural waste disposal. The introduction of anaerobic digestion (biogas) technology is viewed as a proactive step to address this matter as well as a means of strengthening sustainable farming practises. This proposal will also serve to reduce the negative impacts to the environment associated with agricultural waste and at the same time add a component to farm diversification.

The production of biogas is also a source of clean renewable energy. Abbotsford is pleased to be the first community in British Columbia to have an anaerobic digester and is supportive of initiatives that develop energy alternatives. The benefits of such a facility include the reduction of greenhouse gas emissions and assisting the City in meeting its obligations under Bill 27.

The City of Abbotsford is pleased to support Terasen Gas in its pursuit to deliver biogas through its existing infrastructure as it will help serve to address the issues of agricultural waste disposal and aid the City in its efforts to combat climate change.

Yours truly,

George W. Peary
Mayor

c. Council Members
Frank Pizzuto, City Manager
Jay Teichroeb, General Manager of Economic Development & Planning Services

ELECTORAL AREAS

A- GOLDEN-COLUMBIA
B- REVELSTOKE-COLUMBIA
C- SOUTH SHUSWAP
D- FALKLAND-SALMON VALLEY
E- SICAMOUS-MALAKWA
F- NORTH SHUSWAP-SEYMOUR ARM

MUNICIPALITIES

GOLDEN SALMON ARM
REVELSTOKE SICAMOUS

781 MARINE PARK DRIVE NE
BOX 978 SALMON ARM BC
VIE 4P1
TEL: (250) 832-8194
FAX: (250) 832-3375
TOLL FREE: 1-888-248-2773
WEBSITE: www.csrd.bc.ca

2009 01 20 FILE: 5360 36 01

Scott Gramm, Business Development Manager
Terason Gas Inc.
16705 Fraser Highway
SURREY, BC, V4N 0E8

RE: Letter of Endorsement –Biogas Upgrading Project

The Columbia Shuswap Regional District (CSRD) is pleased to provide this letter of endorsement to Terasen Gas Inc. (Terasen) to support its application to the British Columbia Utilities Commission (BCUC) for the development of biogas upgrading projects in British Columbia.

The CSRD is committed to becoming a leader in environmental stewardship and sustainability in working with all stakeholders to implement practices that use fewer resources, reduce climate change and reduce the CSRD's ecological footprint. Developing and implementing a landfill gas upgrading project with Terasen at the CSRD's Salmon Arm landfill site is a great example of how cooperation with industry can accelerate existing plans to align with the provincial government greenhouse gas reduction strategy. Terasen has proved to be a valuable partner in the conceptual development of this project at the Salmon Arm Landfill.

Partnering with Terasen will provide several benefits to the CSRD:

1. **External capital investment will harvest more value from the landfill project.** Without Terasen's capital investment commitment, it is unlikely that the gas capture project at the landfill would have gone beyond the minimum requirements of simply capturing and flaring the gas generated at the landfill. As a regional district, capital budgets are difficult to increase when there is a direct influence on area taxes or fees.
2. **A stable partner**. Working with Terasen, rather than an independent developer reduces long-term financial risk and the assurance that the CSRD will not be left with an abandoned project or a poorly maintained facility.
3. **Established customer service network**. Terasen can provide on-site support for the biogas plant with fully qualified field staff already located in the local area

and the CSRD can avoid additional investment in maintenance. In addition, local Terasen staff will readily be able to call, if necessary, on the knowledge, expertise and resources from elsewhere in their company.

4. **Improved environmental benefits**. By partnering with Terasen, additional environmental benefits can be gained in the form of a more efficient end-use for the gas at the landfill.

If you require any further information, please feel free to contact me at your convenience.

Yours very truly,

Darcy Mooney,
Waste Management Co-ordinator
Columbia Shuswap Regional District

DM

David
Suzuki
Foundation

2211 West 4th Avenue
Suit 219
Vancouver BC
Canada V6K 4S2

604 732 4228 tel
604 732 0752 fax
www.davidsuzuki.org

April 5, 2010

RE: Letter of support for Terasen Gas's initiative to bring renewable biogas to its residential gas customers in BC

Dear British Columbia Utilities Commission (BCUC),

I am writing in support of Terasen Gas's proposal to bring biogas to their residential gas customers in BC.

As an organization that campaigns for climate change and clean energy solutions the David Suzuki Foundation (DSF) supports reducing the greenhouse gas intensity of traditional energy sources while spurring investment in clean energy alternatives. Making biogas an option for residential natural gas consumers is in line with these goals and will create local clean energy jobs while showcasing biogas as a viable alternative.

DSF is fully supportive of this proposal and encourages the BCUC to support this initiative.

Yours sincerely,

Morag Carter

Morag Carter
Director, Climate Change Program

Pacific Carbon Trust

April 27, 2010 Ref: 201006

Terasen Gas Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8
Attention: David Bennett

Dear David:

Re: **Terasen Gas Inc. Renewable Biogas**

Pacific Carbon Trust (PCT) is pleased to prepare this letter of support for the Terasen Gas renewable biogas project which has been filed for approval with the British Columbia Utilities Commission.

Our mandate is to deliver high quality, BC-based carbon offsets to help clients meet their carbon reduction goals and to support the growth of the carbon economy in British Columbia. Terasen's biogas project has the potential to help PCT meet its mandate and also contributes to the Province's commitment to reduce greenhouse gas emissions under the BC Climate Action Plan. This innovative project helps reduce emissions from the waste and agriculture sectors while producing renewable biogas. PCT encourages the development and implementation of these types of projects in British Columbia.

Please feel free to contact me if Pacific Carbon Trust can provide additional information related to our support of the demonstration project.

Sincerely,

D. Scott Macdonald
Chief Executive Officer

6th Floor, 747 Fort Street, Victoria, BC, V8W 3E9 Telephone: 250-952-6793 Facsimile: 250-952-6783 www.pacificcarbontrust.com

March 22, 2011

Mr. Mark Grist,
FortisBC Energy Inc.
Manager Business Development
16705 Fraser Highway
Surrey B.C. V4N 0E8

Dear Mr. Grist,

The Commercial Energy Consumers ("CEC") Association of BC is writing to you at this point in time to communicate its views with respect to the provision of FortisBC Energy Inc. ("FEI") Energy Efficiency and Conservation ("EEC") funds to support the transition of diesel oil fuelled transportation markets to natural gas fuelled transportation, particularly for the trucking component of the transportation market.

The CEC has supported the provision of FEI's EEC funds to transforming the transportation market and continues to support FEI in allocating EEC funds to this purpose for one very simple reason; it is in the interest of FEI's customers, the ratepayers. The CEC believes all ratepayers and specifically the commercial ratepayers will benefit significantly from investing in the transformation of this market. The CEC has been supportive of FEI in moving to capture this opportunity for its customers and critical whenever the movement to capture this opportunity is moving too slowly or not being planned aggressively enough.

The CEC is putting forward this position to FEI because at the stakeholder workshop, held to discuss EEC programs, we were informed of issues arising from the recent interim decision of the BC Utilities Commission ("BCUC") with respect to the Waste Management contracts and initiative being undertaken by FEI. We understand from FEI that it is interested in stakeholder's views with respect to these initiatives and that FEI might like to include these views in its submissions to the Commission relative to its planned filing with the BCUC of FEI's 2010 Report on its EEC Programs.

We understand that the Commission's recent decision may have created some uncertainty with respect to FEI providing funds to support the Waste Management initiatives and potentially with respect to advancing the transformation of the trucking transportation markets in general. The CEC would like to see this uncertainty resolved as soon as possible. The CEC would therefore support a reconsideration of the decision leading to the uncertainty or any plan to have clarification and certainty returned to the FEI transportation market transformation initiatives. We understand that FEI believes that the best opportunity to seek the required certainty would be found in BCUC regulatory process considering the issues in conjunction with the FEI 2010 EEC Report. The CEC would therefore support any initiative by FEI or the BCUC to consider the funding issues as part of the FEI 2010 EEC Report filing.

509-1190 Melville Street, Vancouver, BC V6E 3W1
T: 604-568-4904 F: 604-568-4595

The CEC has been an active participant in the original FEI EEC application made in 2008, has been an active participant in the 2010-2011 FEI Revenue Requirements Application ("RRA") regulatory process, including being a signatory to the Negotiated Settlement Agreement ("NSA") arising from that process, is involved in the current BCUC regulatory process considering the approval criteria for Natural Gas for Vehicles ("NGV") initiatives and the CEC has attended all of the EEC stakeholder workshops held since FEI instituted these consultation processes in 2009. As a consequence the CEC believes that it is reasonably informed with respect to the issues involved.

Over the course of these various regulatory proceedings the CEC has come to understand the attractiveness of the FEI NGV Programs for all customers and specifically for the CEC commercial sector. The CEC would characterize the FEI approach with respect to its NGV initiatives as having been and continuing to be nothing but open and transparent. The CEC believes that FEI has worked diligently to build understanding and support for its NGV initiatives. The CEC has directly been involved in the regulatory processes, in which the CEC believed that FEI was being provided the CEC support and consent to both pursue these NGV initiatives and to fund these initiatives from EEC funds. The CEC is precluded (as a consequence of confidentiality provisions) from discussing the specific content of discussion in a Negotiated Settlement Process ("NSP") but may disclose its own positions at any time. The CEC believes that its sign off with respect to the RRA NSA carried the weight of its support for FEI providing funding for its NGV initiatives. Specifically the CEC believes that item 14 of the NSA supports the fuelling and transportation services to be provided and that item 11 of the NSA supports the funding envelope for the Innovative technologies for 2010-2011. The CEC in stakeholder consultation both in group processes and in numerous other consultations FEI has provided the CEC the opportunity for input, has consistently voiced the view that the NGV opportunity needs to be pursued vigorously. The CEC notes that FEI has also been cautious to ensure that it is trying to pursue these opportunities prudently and has taken the time to do so in a number of ways. The CEC believes that the current uncertainty may arise as from a perspective on a technicality with regard to FEI's ability to provide funding for the NGV programs. The CEC believes that substance should trump technicality, although the CEC with respect supports FEI's efforts to review the issues.

In substance, the CEC believes that the FEI NGV initiatives have a positive Total Resource Cost ("TRC") both independently and as part of the FEI EEC programs. The CEC believes that funding from the Innovative Technologies Program ("ITP") exceeds a TRC of 1 when including the NGV funding. The CEC understands that the NGV initiatives result in environmental reduction of greenhouse gases emissions from transportation use of fuel. Where this can be done with a positive TRC the CEC is particularly supportive and has expressed strong support for this strategic direction of FEI.

The CEC understand that whether it is dealing with BC Hydro ("BCH") Electricity Conservation and Efficiency ("ECE") programs or the FEI EEC programs that the fundamental principle has not been to micro-manage every program and every component of the program for basic regulatory efficiency reasons. The CEC believes that FEI has the ability to make changes, refinements or even switches of specific funding activity from the submissions it makes with respect to EEC programs at any given point in time. The CEC believes that FEI can be held accountable for the prudence of its management in after the fact review processes enabled by the BCUC regulatory processes. The CEC believes that the TRC test accountability as well as the specific program reporting accountability and the frequent stakeholder consultation opportunities the CEC is engaged in provide an ample framework for ensuring that FEI is at risk and accountable for its decisions with respect to the prudent management of the EEC funds.

The CEC believes that it has sufficient access to regulatory processes to ensure that customer perspectives are incorporated into the BCUC's final decisions with respect to the public interest. In this case the CEC believes that the FEI NGV activities are substantially in the public interest and that prolonged uncertainty with respect to funding would be counterproductive to the best interest of the ratepayers.

The CEC supports the use of EEC funds for FEI's NGV programs specifically understanding that these funds are recovered through the delivery margin from ratepayers and not directly from specific rates charged to NGV users. The CEC supports this because tf the contribution it believes this program may provide to all customers as a strategic direction for FEI and its customers.

The CEC will support whatever process FEI or the BCUC take in regard to obtaining an early resolution of the uncertainties arising from the Waste Management interim decision and specifically the FEI initiative to have these issues considered as part of its 2010 EEC Report filing. The CEC will support and participate fully in any expedited process to achieve an early resolution to the uncertainty, because the CEC believes that commercialization initiatives need the nurturing of appropriate degrees of certainty to ensure that the benefits can be developed and captured for the FEI customers and specifically those the CEC represents.

Yours truly,

David Craig
Executive Director
Commercial Energy Consumers

DWC/amp

5 - 4217 Glanford Avenue
Victoria, BC Canada V8Z 4B9
(250) 744-2720
info@bcsea.org

21 March 2011

To:
Shawn Hill,
FortisBC
Vancouver, BC
By email: shawn.hill@fortisbc.com

Dear Shawn,

Re: FortisBC's Energy Efficiency and Conservation Plan Annual Report

This is to confirm that, as an active participant in the 2009 Energy Efficiency and Conservation Application of Terasen Gas, and a current member of FortisBC's EEC Stakeholder Group, the BC Sustainable Energy Association supports the use of FortisBC's EEC program to incent the purchase of heavy duty NGVs in place of diesel-powered vehicles where cost effective, primarily because of the greenhouse gas emissions reductions benefits. (BCSEA does not support incentives for fuel switching toward natural gas in the *passenger* vehicle sector, where hybrid and plug-in electric vehicles are on the cusp of achieving substantial market penetration.) BCSEA believes that using EEC monies in this instance is consistent with the objectives of the *Clean Energy Act* and other government policies on energy efficiency and greenhouse gas reductions.

Regards,

Thomas Hackney,
Vice-President for Policy

March 22, 2011

Dave Bennett
Director Resource Planning & Market Development
FortisBC Energy Inc.
16705 Fraser Hwy
Surrey, BC
V4N 0E8

RE: EEC Funding of NGVs

Dear Mr. Bennett:

This letter is to confirm that The City of Vancouver has been a participant in stakeholder review sessions held by FortisBC regarding Energy Efficiency and Conservation (EEC) programs. We confirm that two stakeholder review sessions were held in 2010 (March and November) and that NGV programs were presented and discussed at these sessions. The City of Vancouver supports the continuation of the program to provide NGV incentives for heavy duty vehicle applications as adoption of NGVs in these markets provides GHG reductions and fuel cost savings to operators of NGVs.

Sincerely yours,

Sean Pander
Assistant Director, Sustainability Group
City of Vancouver

City of Vancouver, Office of the City Manager
453 West 12th Avenue
Vancouver, British Columbia V5Y 1V4 Canada
tel: 604.871.6542 *fax:* 604.673.8169
website: vancouver.ca

BCAOMA
www.bcapartmentowners.com
Promoting and sustaining residential housing in BC

Mark Grist
Manager, Business Development
Fortis BC Energy Inc.
16705 Fraser Hwy
Surrey, BC
V4N 0E8

Re: Letter of Support - Stakeholder Review of FortisBC EEC Programs

Dear Mr. Grist:

Further to our discussions at the EEC Stakeholder meeting held on March 15, 2010, the BC Apartment Owners & Managers Association (BCAOMA) would like to express its support for the use of Energy Efficiency & Conservation program incentives to encourage the use of Natural Gas Vehicles within BC's heavy duty transportation markets. The BCAOMA participated in stakeholder review sessions organized by FortisBC and had the opportunity to review and comment on the planned use of incentives to encourage the adoption of NGVs. During the November 24, 2010 session FortisBC provided a detailed presentation on the NGV program for BC, including the proposed use of EEC funding under the Innovative Technologies program. This presentation was favourably received by the stakeholder group. The BCAOMA believes that this consultation process meets the "Accountability Measures" defined in the Commission EEC Approval Decision G-36-09 and supports FortisBC's view that it has the necessary approvals to proceed with the NGV incentive program. The BCAOMA support this program as it has significant potential to reduce GHG emissions in the transportation sector while providing delivery rate revenues that will benefit all users of the FortisBC system.

Sincerely yours,

Marg Gordon

Marg Gordon
Chief Executive Officer
BC Apartment Owners and Managers Association

BC APARTMENT OWNERS AND MANAGERS ASSOCIATION
203–1847 WEST BROADWAY, VANCOUVER, BC V6J 1Y6
PHONE: 604.733.9440 | FAX: 604.733.9420 | TOLL FREE IN BC: 1.877.700.9440

March 23, 2011

Mark Grist
Manager, Business Development
Fortis BC
16705 Fraser Highway
Surrey, B.C. V4N 0E8

Dear Mark,

I am writing in followup to the meeting of Fortis BC Energy Efficiency and Conservation Stakeholder Meeting on March 15, 2011.

The Fraser Basin Council is a non-profit organization with a mandate of advancing sustainability in British Columbia, with a focus on the Fraser River watershed. We participate in the Fortis BC EEC Stakeholder sessions, as one of our strategic priorities in action on climate change and air quality.

Over the past six years, one component of FBC's climate change work has been to engage public and private sector vehicle fleets on emissions reduction activities, as a key leadership area in the transportation sector. This includes the delivery of a national green rating system – E3 Fleet – that provides third-party green certification of vehicle fleets. We have over 100 members in the program across Canada. We are technology and fuel neutral, and work with leading fleets to implement a variety of practices that reduce emissions and fuel costs.

Through our involvement in the EEC Stakeholder group over the past two years, we have been informed of Fortis BC's ongoing plans to provide incentives for natural gas vehicles (NGVs) and interest in providing natural gas compression and refueling service. We are supportive of this effort by Fortis BC to provide incentives for NGV purchase, and are also supportive of Fortis BC providing natural gas compression and refueling service. We have noticed, based on recent unsolicited calls from fleets, that there is growing interest amongst the fleets that we work with in exploring the use of natural gas as one means for reducing emissions. We also know that incentives are required to assist in overcoming the barrier of increased capital cost for NGVs. In addition, our experience in working with fleets is that in many cases there is a need for third-parties such as Fortis BC who can provide refueling services.

1st. Floor, 470 Granville Street, Vancouver, BC, Canada V6C 1V5
Tel: (604) 488-5350 Fax: (604) 488-5351 Email: info@fraserbasin.bc.ca **www.fraserbasin.bc.ca**

Fraser Basin Council

If you have any questions, please do not hesitate to contact me at 604-488-5359 or via email at jvanderwal@fraserbasin.bc.ca.

Sincerely ,

Jim Vanderwal
Senior Manager

1st. Floor, 470 Granville Street, Vancouver, BC, Canada V6C 1V5
Tel: (604) 488-5350 Fax: (604) 488-5351 Email: info@fraserbasin.bc.ca **www.fraserbasin.bc.ca**

Bevacqua, Ilva

From:	Regulatory Affairs Terasen Gas
Sent:	November 13, 2009 5:45 PM
To:	Commission Secretary (Commission.Secretary@bcuc.com)
Cc:	'Nakoneshny, Philip BCUC:EX'
Subject:	Terasen: Energy Efficiency and Conservation Stakeholder Group - Invitation
Attachments:	EEC Stakeholder Group Invitation.pdf

Please be advised that the attached invitation to the Terasen EEC Stakeholder Group has been sent to stakeholders. Please forward this invitation to the appropriate staff members who should be made aware of and may choose to participate in this Group. Please refer to the attached information and please contact jenny.chia@terasengas.com for further details.

Regards,

Ilva Bevacqua
Regulatory Governance Advisor
Terasen Gas Inc.
16705 Fraser Highway, Surrey, B.C. V4N 0E8
Direct: (604) 592-7664 **Mobile:** (604) 209-9347 **Fax:** (604) 576-7074
mailto:ilva.bevacqua@terasengas.com visit us at www.terasengas.com

Regulatory Affairs Correspondence: mailto:regulatory.affairs@terasengas.com

---

From: Regulatory Affairs Terasen Gas
Sent: November 13, 2009 5:34 PM
To: Al Kemp (alkemp@suites-bc.com); B.C. Public Interest Advocacy Centre (support@bcpiac.com); Chad Painchaud (chad.painchaud@directenergy.com); Chris F. Weafer (cweafer@owenbird.com); Craig P. Donohue (cdonohue@png.ca); Duane Chapman (Duane.Chapman@gov.bc.ca); Eugene Kung (ekung@bcpiac.com); info@suites-bc.com; James Wightman (jwightman@econalysis.ca); Jim Fraser (jim.fraser@bcuc.com); Joanna Sofield (bchydroregulatorygroup@bchydro.com); Joyce Martin (joyce.martin@fortisbc.com); Joyce Martin (regulatory@fortisbc.com); Leigha Worth (lworth@bcpiac.com); Thomas Hackney (thackney@shaw.ca); William J. Andrews (wjandrews@shaw.ca); Al Kemp (alkemp@suites-bc.com); B.C. Public Interest Advocacy Centre (support@bcpiac.com); BC Hydro Regulatory Group (bchydroregulatorygroup@bchydro.com); Brian Williston (brian.williston@bcuc.com); Chris F. Weafer (cweafer@owenbird.com); David Bursey (dwb@bht.com); Duane Chapman (Duane.Chapman@gov.bc.ca); Eugene Kung (ekung@bcpiac.com); Geoffrey Higgins (higginsenergy@canada.com); Gordon A. Fulton (gfulton@boughton.ca); James Wightman (jwightman@econalysis.ca); Jim F. Langley (jim.langley@bp.com); Joyce Martin (regulatory@fortisbc.com); Karl E. Gustafson (kgustafson@lmls.com); Leigha Worth (lworth@bcpiac.com); Lloyd G. Guenther (lguenther@novuscom.net); Lori Winstanley (lwinstanley@cope378.ca); Mary McCordic (mary.mccordic@shell.com); Nelle Maxey (office@teca.ca); Nick Caumanns (nick.caumanns@shell.com); Paula Barrett (paula.barrett@gov.bc.ca); Pierre Lamarche (Pierre.Lamarche@hspp.ca); Ray Aldeguer (alice.ferreira@bchydro.com); Al Kemp (alkemp@suites-bc.com); Chad Painchaud (chad.painchaud@directenergy.com); Charles W. Bois (cbois@millerthomson.ca); Chris F. Weafer (cweafer@owenbird.com); Craig P. Donohue (cdonohue@png.ca); David Bursey (dwb@bht.com); David J. Newlands (dnewlands@telus.net); Duane Chapman (Duane.Chapman@gov.bc.ca); Eugene Kung (ekung@bcpiac.com); Gary Newcombe (gary.newcombe@directenergy.com); Geoffrey Higgins (higginsenergy@canada.com); Gordon A. Fulton (gfulton@boughton.ca); James L. Quail (support@bcpiac.com); James Wightman (jwightman@econalysis.ca); Jim F. Langley (jim.langley@bp.com); Joanna Sofield (bchydroregulatorygroup@bchydro.com); Joyce Martin (regulatory@fortisbc.com); Ken Donison (ken.donison@corix.com); Leigha Worth (lworth@bcpiac.com); Lori Winstanley (lwinstanley@cope378.ca); Mary McCordic (mary.mccordic@shell.com); Nelle Maxey (office@teca.ca); Nick Caumanns (nick.caumanns@shell.com); Paula Barrett (paula.barrett@gov.bc.ca); Richard O'Callaghan (rto@rtocallaghan.com); Ron Cliff (ron@highcliff.ca); Timothy.Mosley@bchydro.com; Terry_Milligan@bcit.ca; lworth@bcpiac.com;

mayorandcouncil@kelowna.ca; mayor@city.pg.bc.ca; dpasacreta@crosbypm.com; Veerman, Keith (Fortis BC); info@chbakelowna.bc.ca; sislager@shawcable.com; cedge@chbavictoria.com; erik.kaye@gov.bc.ca; jcockbur@nrcan.gc.ca; dwcraig@allstream.net; bpurdy@fraserbasin.bc.ca; dwaynemcneil@seabirdisland.ca; buddy_joseph@squamish.net; mgordon@bcaoma.com
Subject: Terasen: Energy Efficiency and Conservation Stakeholder Group - Invitation

Please refer to the attached information regarding Terasen's EEC Stakeholder Group. For more information, please contact jenny.chia@terasengas.com.

Regards,

Ilva Bevacqua
Regulatory Governance Advisor
Terasen Gas Inc.
16705 Fraser Highway, Surrey, B.C. V4N 0E8
Direct: (604) 592-7664 **Mobile:** (604) 209-9347 **Fax:** (604) 576-7074
mailto:ilva.bevacqua@terasengas.com visit us at www.terasengas.com

Regulatory Affairs Correspondence: mailto:regulatory.affairs@terasengas.com

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 576-7220
Toll Free: 1-800-773-7001
www.terasengas.com

November 13, 2009

Dear Stakeholders and Interested Parties:

Re: Terasen Gas - Energy Efficiency & Conservation Stakeholder Group

This year Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. (collectively “Terasen Gas”) received approval from the British Columbia Utilities Commission (“BCUC”) for an expanded Energy Efficiency and Conservation (“EEC”) portfolio to provide customers with enhanced tools and incentives to manage their natural gas consumption, reduce their energy costs, and lower their greenhouse gas emissions. The newly approved $41.5 million portfolio includes rebates and incentives on a number of energy efficient appliances, equipment and systems, as well as educational and outreach initiatives for residential and commercial customers, and those customers in the affordable housing sector.

Terasen Gas recognizes the need for accountability for the approved funds and believes that engaging an EEC stakeholder group would be beneficial to guide and inform EEC activity. We are seeking representation from the following areas:

- Provincial, municipal, and First Nation governments
- Non-Governmental Organizations
- Consumer advocates, representing residential customers
- Affordable housing advocates
- Commercial customers
- Trade organizations
- Equipment manufacturers
- Other utilities

To add transparency and accountability to our EEC portfolio, we intend to hold bi-annual EEC workshops with stakeholders, at which we will present updates on program progress and monies allocated. The one-day workshops would also act as a forum for stakeholder input on developing new programs and refining existing programs.

The first stakeholder meeting proposed will be either **Tuesday December 8** or **Wednesday December 9, 2009** in Vancouver.

We respectfully invite your participation in Terasen’s EEC Stakeholder Group. Please contact me via email at jenny.chia@terasengas.com or via phone 604.592.7645 if you are interested in joining the Terasen EEC Stakeholder Group or if you have any questions. If you require financial and booking assistance with travel arrangements from outside the Lower Mainland, we would be pleased to assist you with those. Please confirm your participation in the Terasen EEC Stakeholder Group by **Monday November 23, 2009.**

Regards,

Jenny Chia

Jenny Chia
Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.

Ghavami, Negar

From: Nir Kushnir <nkushnir@nee.ca>
Sent: Tuesday, November 24, 2009 9:52 AM
To: Chia, Jenny
Subject: Re: Terasen: Energy Efficiency and Conservation Stakeholder Group - Invitation

I will be there

From: Chia, Jenny <Jenny.Chia@terasengas.com>
To: Nir Kushnir
Sent: Tue Nov 24 11:51:44 2009
Subject: Terasen: Energy Efficiency and Conservation Stakeholder Group - Invitation

Hi Nir,

Gary Lengle has indicated that you would be interested in joining the EEC stakeholder group. Please consider the attachment as an invitation to join. Based on some of the other attendees' responses, we have confirmed the date to be Wednesday December 9, 2009.

The meeting will be at the Sheraton Vancouver Wall Centre Hotel on 1088 Burrard Street in downtown Vancouver.

This will be a full day event with meals served. Please let me know if you have any dietary restrictions.

I will be sending out an agenda a couple of days prior.

And if you are unable to make the meeting this time, I will be happy to send you the meeting minutes after.

Regards,

Jenny

Jenny Chia

EEC Communications, Education, and Outreach Manager
Terasen Gas Inc.
Phone: 604-592-7645
Fax: 604-592-7670

EEC Stakeholder Group

The Companies recognized the need for accountability in the EEC Application and proposed to form and engage an EEC Stakeholder Group. The objectives of the EEC Stakeholder Group are to guide and provide input on EEC activity.

List of EEC Stakeholder Members (as of March 15, 2011)

Member	Organization	Title
Marg Gordon	B.C. Apartment Owners and Managers Association	Chief Executive Officer
Steve Hobson	BC Hydro	Director Power Smart
Rob Noel	BC Mechanical Contractors Assoc	Commercial contractors
Mary McWilliam	BC Non Profit Housing Association	Director of Strategic Energy Management
Jim Quail	BC Public Interest Advocacy Centre	Executive Director
Erik Skehor	BC Safety Authority	Operations Manager
Tom Hackney	BC Sustainable Energy Association	Vice-President of Policy
Alison Richter	BC Utilities Commission	Regulatory Analyst - First Nations and Sustainability
MJ Whitemarsh	Canadian Home Builders' Association of BC	President
Craig Williams	Canadian Manufacturers and Exporters	Vice President
Mike Todd	Canfor Pulp	Energy Manager
Stuart Gairns	Canfor Pulp	PGI Energy Leader
Mark Hartman	City of Vancouver	Buildings Energy Programs Manager
Tony Gioventu	Condominium Home Owners' Association	Executive Director
David Craig	Consolidated Management Consultants	President
Joan Huzar	Consumers Council of Canada	
Dan Pasacreta	Crosby Property Managements, Ltd	Licensed Strata Agent
Keith Veerman	FortisBC Inc.	Manager-Energy Efficiency
Bob Purdy	Fraser Basin Council	Director, External Relations & Corporate Development
Amy Spencer-Chubey	Greater Vancouver Home Builders' Association	Director of Government Relations
Gord Monro	Heating, Refrigeration and Air Conditioning Institute of Canada	Contractor Division BC Regional
Richard Siegenthaler	Hemmera	Renewable Energy Specialist
Bruce Macgowan	IBC Technologies Inc.	President
Andrew Pape-Salmon	Ministry of Energy and Mines	Director Energy Efficiency Branch
Nir Kushnir	National Energy Equipment	General Manager, Trane
Elizabeth Westbrook	Natural Resources Canada	Senior Officer, Stakeholder Relations
Nina Winham	New Climate Strategies	Consultant and Rate 1 customer
Al Kemp	Rental Owners and Managers Society of BC	CEO
Cindy Stern	Tseshaht First Nation	Chief Operating Officer
Jeff Fischer	Urban Development Institute	Deputy Executive Director

Appendix C

Studies

1. Alternative Energy Surveys

2. Biogas Market Study

3. Residential Customer Satisfaction Research

SURVEY CONDUCTED FOR TERASEN

Alternative Energy in British Columbia

Methodology

From July 31 to August 2, 2009 Angus Reid Strategies conducted an online survey among a randomly selected, representative sample of 802 adult residents of British Columbia who are Angus Reid Forum panelists. The margin of error—which measures sampling variability—is +/- 3.5%, 19 times out of 20. The results have been statistically weighted according to the most current education, age, gender and region Census data to ensure a sample representative of the entire adult population of British Columbia. Discrepancies in or between totals are due to rounding.

Objectives

The objectives of the study were:

- To find out the level of awareness and knowledge of alternative energy sources – Solar, Biomass, District Heating Systems and Ground Source Heat Pump, among BC residents.

- To find out whether BC residents who are aware of alternative energy sources are willing to pay extra to incorporate an alternative energy source in their home.

- Tto find out whether customers expect Terasen Gas to provide these alternative energy sources.

Familiarity with Alternative Energy or Green Energy

Base: 802 respondents in BC

- One-in-four BC residents (26%) are very familiar with the terms Alternative Energy or Green Energy, and two-in-four (43%) are familiar with them. Only five per cent have never heard of the terms, and 26 per cent have heard of them, but are not familiar with them.

CONTACT:
Hamish Marshall, Research Director, Public Affairs, 604-647-1987, hamish.marshall@angus-reid.com

- The highest level of familiarity with Alternative Energy or Green Energy (those who responded very familiar or familiar) is in Vancouver Island (76%), among people aged 18 to 34 (72%), those living in households earning more than $100,000 a year (76%) and university graduates (75%).

Awareness of Energy Sources

Base: 773 respondents in BC who have heard of, are familiar, or are very familiar with Alternative Energy or Green Energy

- All respondents (100%) are aware of solar energy (60% very aware, 40% aware).
- Three-in-four respondents (77%) are aware of ground source heat pumps (31% very aware, 46% aware).

- Half of respondents (53%) are aware of biomass energy (13% very aware, 40% aware).

- Two-in-five respondents (39%) are aware of district heating systems (7% very aware, 33% aware).

- Awareness of ground source heat pumps increases with household income (from 69% among those living in households earning less than $50,000 a year, to 86% among those living in households earning more than $100,000 a year) and age (from 69% for respondents aged 18 to 34, to 84% for those over the age of 55).

- Awareness of biomass energy increases with household income (from 52% among those living in households earning less than $50,000 a year, to 62% among those living in households earning more than $100,000 a year) and education (from 49% for respondents with a high school education or less, to 60% for university graduates).

- Awareness of district heating systems increases with household income (from 32% among those living in households earning less than $50,000 a year, to 46% among those living in households earning more than $100,000 a year) and age (from 32% for respondents aged 18 to 34, to 43% for those over the age of 55).

Hamish Marshall, Research Director, Public Affairs, 604-647-1987, hamish.marshall@angus-reid.com

Knowledge of Energy Sources and Technology

Base: 773 respondents in BC who have heard of, are familiar, or are very familiar with Alternative Energy or Green Energy

- 39% of respondents claim to be extremely knowledgeable or very knowledgeable of solar energy; 55% are somewhat knowledgeable.
- 19% of respondents claim to be extremely knowledgeable or very knowledgeable of ground source heat pumps; 41% are somewhat knowledgeable.
- 8% of respondents claim to be extremely knowledgeable or very knowledgeable of biomass energy; 28% are somewhat knowledgeable.
- 6% of respondents claim to be extremely knowledgeable or very knowledgeable of district heating systems; 23% are somewhat knowledgeable.

Willingness to Incorporate an Alternative Energy Source

Base: 773 respondents in BC who have heard of, are familiar, or are very familiar with Alternative Energy or Green Energy

- Two-thirds of BC residents (69%) are extremely or very willing to incorporate an alternative energy source (Solar, Biomass, District Heating Systems or Ground Source Heat Pumps) if they were buying or building a new home or renovating an existing home.

- The respondents who voiced the highest level of willingness to incorporate an alternative energy source reside in the BC Southern Interior (74%), are older than 55 years of age (74%), and live in households earning less than $50,000 a year (73%).

Paying Extra for a Home that Uses an Alternative Energy Source

Base: 745 respondents in BC who have heard of, are familiar, or are very familiar with Alternative Energy or Green Energy, and who are extremely willing, very willing, or somewhat willing to incorporate an alternative energy source into their home.

- One-in-five BC residents who would incorporate alternative energy to their home (19%) would be willing to pay up to 10% extra for a home that uses an alternative energy source. Two-in-five (41%) would pay up to 5% extra, and 28% would pay from 1% to 2% extra for such a home.

Terasen Gas Providing Alternative Energy Sources

Base: 773 respondents in BC who have heard of, are familiar, or are very familiar with Alternative Energy or Green Energy

- One-third of respondents (33%) believe Terasen Gas should provide these alternative energy sources (Solar, Biomass, District Heating Systems or Ground Source Heat Pumps) for customers, while 19 per cent disagree, 35 per cent answer "maybe", and 12 per cent are undecided.

- Respondents in Metro Vancouver (36%) and the BC Southern Interior (also 36%) are the most willing to say "Yes" to Terasen providing alternative energy to consumers, along with respondents aged 18 to 34 (46%).

Energy Efficiency Improvements

Base: 802 respondents in BC

- One-third of BC residents (34%) have undertaken an energy efficiency improvement in their homes, while one-in-four (24%) are planning to do so. Three-in-ten (29%) have not undertaken any energy efficiency improvements and do not intend to do so.

- Respondents over the age of 55 (40%) were more likely than younger BC residents to have undertaken an energy efficiency improvement, while those living in households earning less than $50,000 a year (34%) were more likely to reject the idea.

Hamish Marshall, Research Director, Public Affairs, 604-647-1987, hamish.marshall@angus-reid.com

Conclusions

- Awareness of alternative energy technologies varies highly by technology – solar power and heat pumps have near universal awareness, while nearly half of the population is unaware of Biomass and over 60% are unaware of district heating systems.

- Despite the apparent low level of knowledge of specific sources (less than 10% for both biomass and district heating systems), many British Columbians are clearly willing to try alternative energy.

- People in the BC Southern Interior, those over the age of 55, and those in the lowest income bracket are particularly supportive of alternative energy (more than 70% are willing to incorporate it in their homes). However, those in lower income households are less likely to undertake energy efficiency improvements.

- A third of BC residents want Terasen Gas to offer alternative energy to its customers, with the strongest support coming from respondents aged 18 to 34.

- One-in-five BC residents would consent to paying an extra 10% for a home that incorporates alternative energy, and just 13 per cent would not pay more at all.

CONTACT:
Hamish Marshall, Research Director, Public Affairs, 604-647-1987, hamish.marshall@angus-reid.com

Angus Reid Strategies is a full-service polling and market research firm which is a leader in the use of the Internet and rich media technology to collect high-quality, in-depth insights for a wide array of clients. Dr. Angus Reid and the Angus Reid Strategies team are pioneers in online research methodologies, and have been conducting online surveys since 1995.

Angus Reid Strategies, along with its sister company, Vision Critical, is now the largest Canadian-owned market research enterprise. In addition to its five offices in Canada—located in Vancouver, Calgary, Regina, Toronto, and Montreal—the firm also has offices in San Francisco, Chicago, New York, London, Paris and Sydney. Its team of specialists provides solutions across every type and sector of research, and currently serves over 200 international clients.

Angus Reid Strategies polls are conducted using the Angus Reid Forum (www.angusreidforum.com), Springboard America (www.springboardamerica.com) and Springboard UK (www.springboarduk.com) online panels, which are recruited via an industry-leading process that incorporates a randomized, widespread invitation approach and a triple opt-in screening procedure. The panels are maintained through state-of-the-art sampling techniques and frequent verifications of personal identity, contact information, and demographic characteristics. These premier online survey platforms present respondents with highly visual, interactive, and engaging surveys, ensuring that panel members provide thoughtful and reliable responses.

Angus Reid Strategies, the only public opinion firm to exclusively use online methods to follow the views of the electorate during the 2008 federal campaign, offered the most accurate prediction of the results of Canada's 40th election.
http://angusreidstrategies.com/uploads/pages/pdfs/2008.10.15_Election.pdf

Since 2006, Angus Reid Strategies has covered eight provincial elections in Canada—more than any other pollster in the country—and the results have accurately predicted the outcome of each of these democratic processes.
http://angusreidstrategies.com/uploads/pages/pdfs/2008.03.28_Anniversary_1.pdf
http://www.angusreidstrategies.com/uploads/pages/pdfs/2008.12.09_QuebecElection.pdf
http://www.angusreidstrategies.com/uploads/pages/pdfs/2009.05.13_BCElection.pdf
http://www.angusreidstrategies.com/uploads/pages/pdfs/2009.06.10_NSElection.pdf

More information on the way Angus Reid Strategies conducts public opinion research can be found at http://www.angusreidstrategies.com/uploads/pages/pdfs/ARS.ARF.WP.pdf

- 30 -

For more information, please contact the researcher listed in the footnote.

CONTACT:
Hamish Marshall, Research Director, Public Affairs, 604-647-1987, hamish.marshall@angus-reid.com

Terasen Gas Alternative Energy Study

December, 2010

Foreword

BACKGROUND

The Terasen Gas Alternative Energy Study was first conducted in 2009 to assess British Columbians' awareness, knowledge, and attitudes towards alternative energy technologies. The study is comprised of two key parts: a qualitative phase involving a series of in-depth interviews with key influencers of energy decisions in British Columbia, and a quantitative omnibus study to measure awareness and adoption of alternative energy options among the general BC population. The 2009 study was conducted by two companies: TNS Canadian Facts provided the in-depth qualitative component while Angus Reid Strategies conducted the omnibus portion. This year, TNS Canadian Facts has undertaken both parts of the study to provide a holistic view on alternative energy. This report presents the findings of the 2010 quantitative omnibus component, and tracks findings against the 2009 results.

OBJECTIVES

The quantitative portion of the Terasen Gas Alternative Energy Study seeks to:

- Explore British Columbians' awareness of alternative energy options, and their knowledge of these technologies;
- Assess the public's willingness to adopt alternative energy technology, and associated with this, their willingness to pay for them; and,
- Determine the role of Terasen Gas in providing energy derived from alternative energy sources.

Foreword

METHODOLOGY

To ensure comparable results, the 2010 study was designed to mimic the 2009 study in scope and methodology.

In total, 800 interviews were conducted with a random sample of BC's population. Interviews were conducted with a representative sample of BC residents who are members of TNS' online panel between November 10 - November 12, 2010. The questionnaire was comprised of eight questions, which were asked in the same sequence and using the same wording as 2009 to allow for direct year-over-year comparisons. The one exception to this was an change in question wording regarding Terasen's role in providing alternative energy (Q6). The question was simplified to make the intention of the question clearer.

Data was weighted in the same way as the 2009 study, on the basis of education, age, gender, and region against BC adult census data. In 2009, data was not weighted by income, and a skew toward the upper-income brackets is noticeable. Because income is an important variable in alternative energy awareness and attitudes, TNS replicated the income proportions in the 2009 study (see pages 18 and 19 for the effects of the weighting).

Summary: Study Year	Field Start	Field Finish	Total Sample	Weighting	Online Panel Supplier
2009	*July 31, 2009*	*August 2, 2009*	*n = 802*	*BC Adult population*	*Angus Reid Strategies*
2010	*Nov 10, 2010*	*Nov 12, 2010*	*n = 800*	*BC Adult population*	*TNS Canadian Facts*

Although the 2010 study mirrored the 2009 version in terms of sample size, weighting, methodology, and survey instrument, there are still a number of caveats to consider when interpreting the results. Studies were conducted using different online panels. Although panel participants are strategically recruited, there is no way to ensure panel sample is representative of the broader population. Furthermore, the reader should bear in mind that the two waves were conducted during different seasons in the year. Seasonality can impact a respondent's mindset on home issues such as heating. As such, substantial shifts in results are possible, but do not necessarily reflect attitudinal changes.

Executive Summary

AWARENESS AND KNOWLEDGE OF ALTERNATIVE ENERGY SOURCES

In 2010, BC residents' awareness of alternative energy sources has decreased from 2009 levels. The downward trend is apparent both for alternative energy in general, and for the specific technologies measured in this study (solar energy, ground-source heating, district heating, and biomass energy). Declining awareness is consistent across the four technologies measured.

Alternative energy knowledge has decreased along with awareness levels. The greatest declines are observed in technologies where BC residents have been the most well-versed since 2009: solar energy and ground source heat pumps. Here, nearly 50% fewer report themselves as "extremely" or "very" knowledgeable in comparison to 2009, yet the proportion indicating some knowledge has risen.

ATTITUDES TOWARD ALTERNATIVE ENERGY

While BC residents still strongly favour incorporating alternative energy sources, they have less pronounced enthusiasm in 2010. Over the past year, those who are "extremely willing" to seek alternative energy sources for a new home purchase or construction has dropped 9%, while more have shifted to the position of being "very willing".

To go along with this trend, fewer are willing to pay the higher premiums toward a home that uses these alternative energy sources. While support remains strong among those who are willing to pay the highest premium (an incremental 10%), support for paying an additional 5% has dropped since last year.

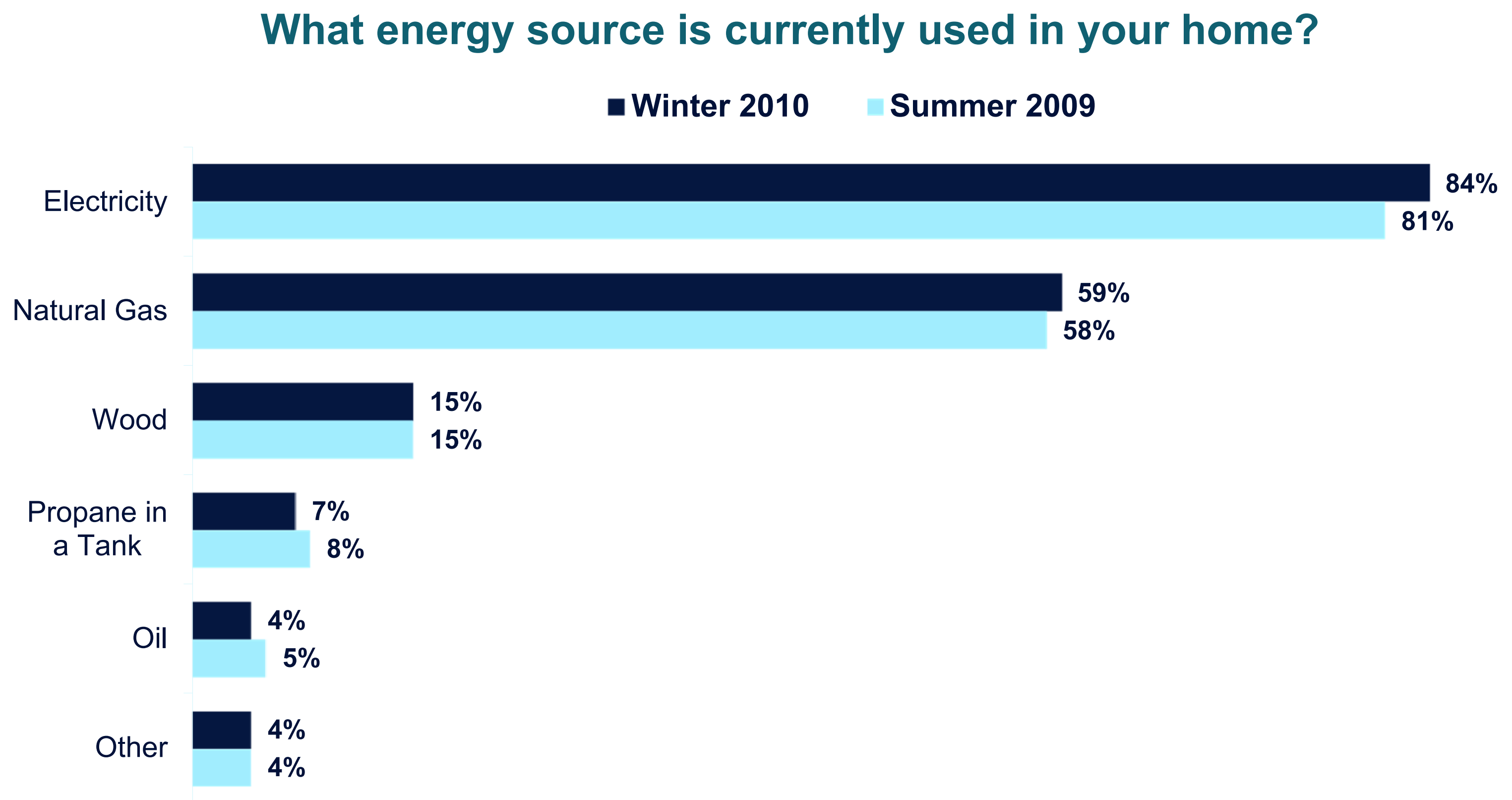
At the same time, fewer BC residents have undertaken energy efficiency improvements this year (down 7%) and more are uncertain about their commitment to energy efficiency practices in the next two years.

Despite British Columbians' lower awareness, knowledge, and attitudes about alternative energy over the past year, it seems that residents are more likely to see a role for Terasen in providing alternative energy options. This year, 51% of BC residents believe Terasen should offer alternative energy sources, up from 33% last year. Residents of the Lower Mainland and young adults (25-34) are more likely than other groups to share this sentiment. As a caution, this question was modified for 2010, and the wording change may have impacted results.

Current Energy Sources

Current Energy Use

BC residents are using similar energy sources relative to 2009. While more than 8 in 10 use electricity and more than half use natural gas in some capacity within their homes, the few who are already employing alternative energy sources in the home are part of the same small minority as 2009 (4%).



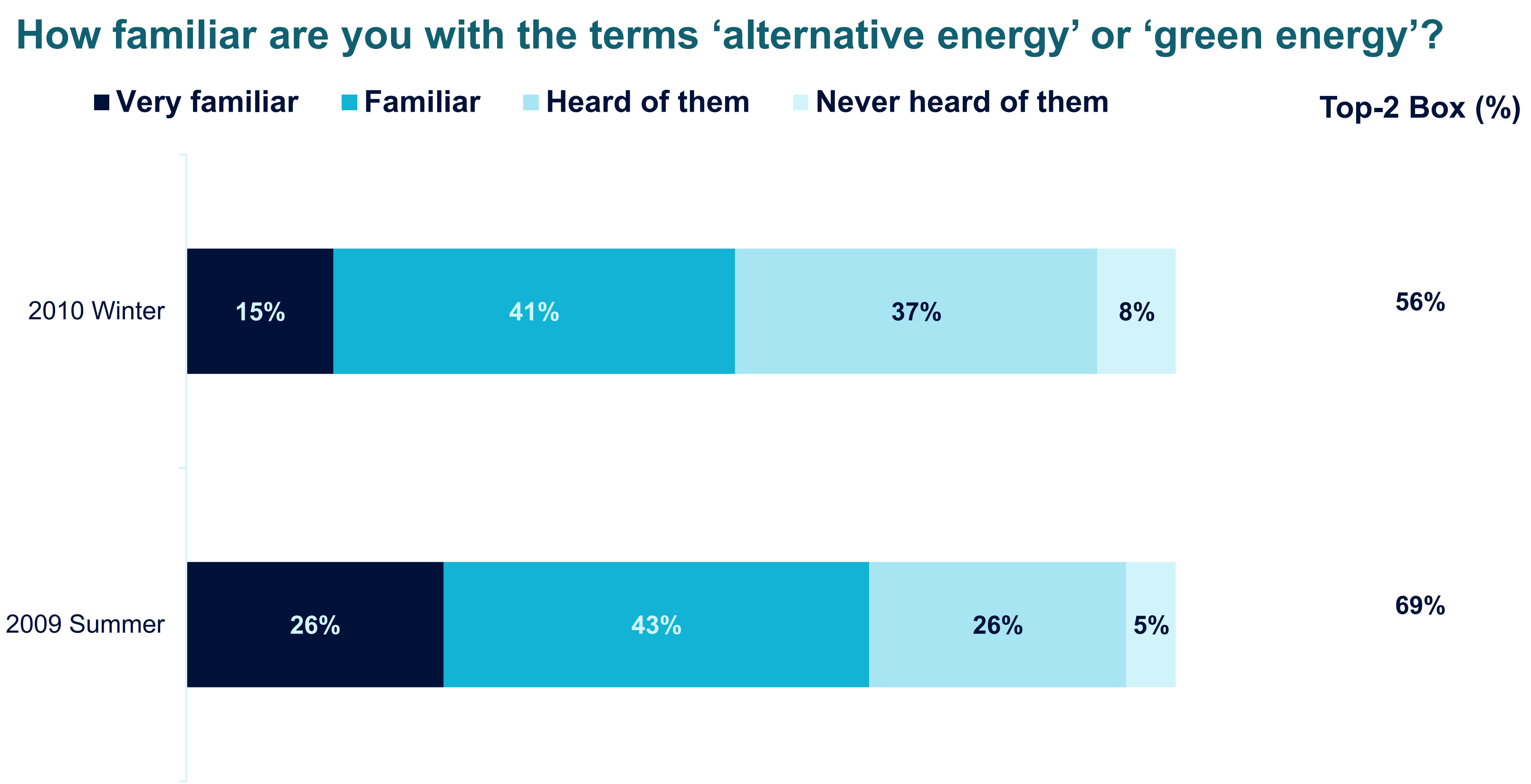
Base All Respondents (2010 n = 800 / 2009 n = 802)

Q8: What energy sources are currently used in your home?

Awareness Of Alternative Energy Options

Awareness Of Alternative Energy Options

This year's study found fewer BC residents reporting a high degree of familiarity with the terms *Alternative Energy* or *Green Energy.* Since 2009, the percentage of those who are very familiar / familiar with either of these terms fell by 13%, a significant difference. However, when those who indicate some familiarity with the terms are included, the result is almost identical year over year (93% in 2010 versus 95% in 2009).

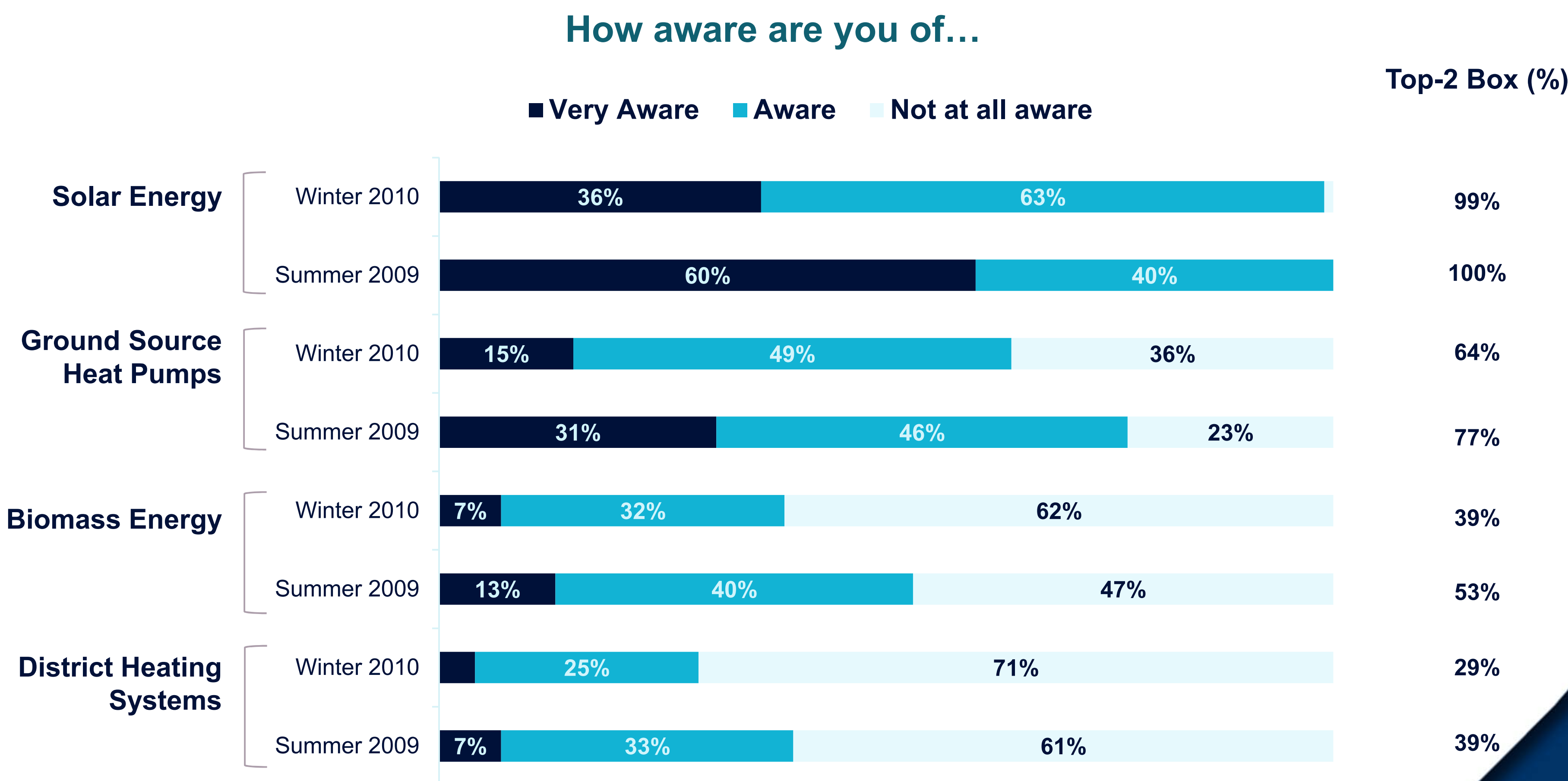


Base All Respondents (2010 n = 800 / 2009 n = 802)

Q1: How familiar are you with the terms alternative energy or green energy?

Awareness Of Alternative Energy Options: By Energy Type

Similar to 2009, BC residents familiar with alternative or green energy are most likely to be aware of solar energy, followed by ground source heat pumps. They remain far less aware of biomass energy and district heating systems. In the 2010 study, almost 50% fewer BC residents say they are very aware of any of these technologies.



Base All respondents familiar with alternative energy (2010 n = 737 / 2009 n = 759)

Q2: How aware are you of the following energy sources?

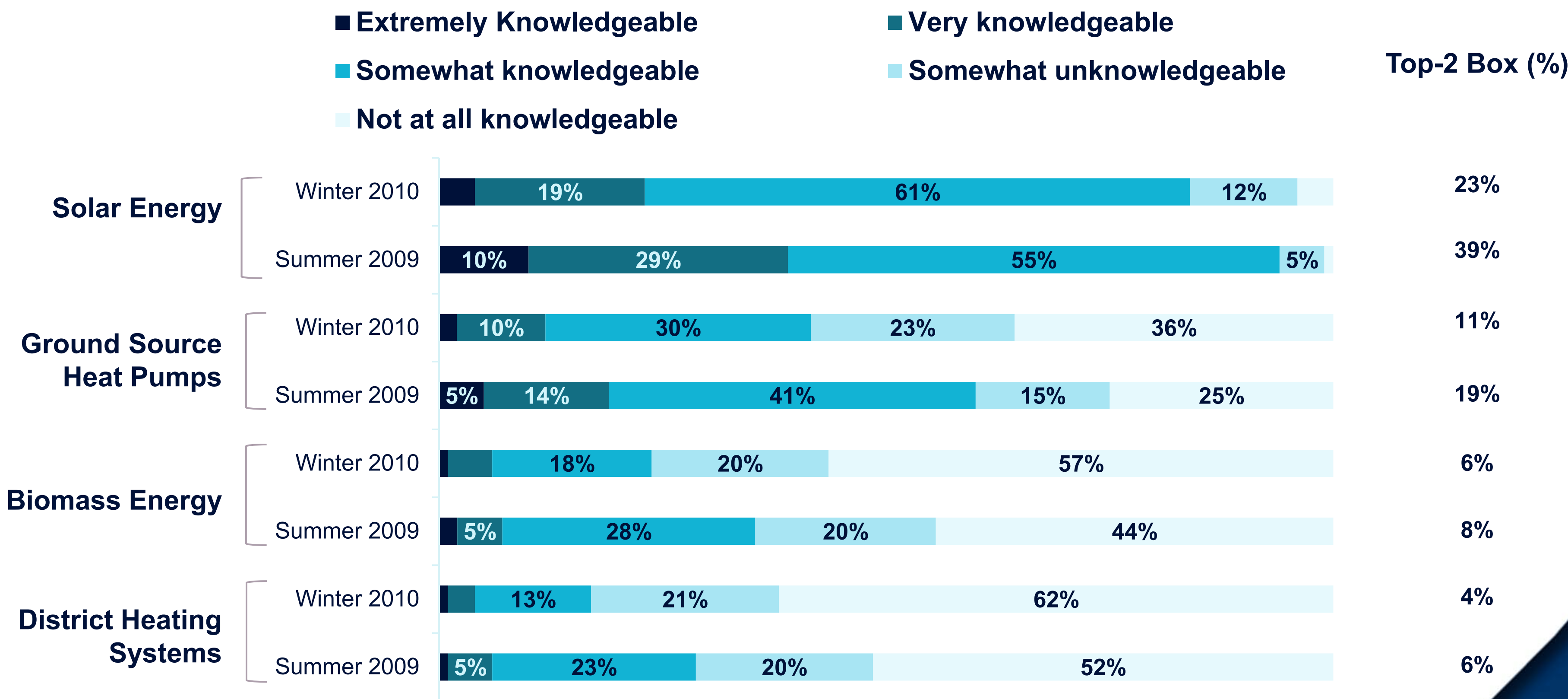
Note: Results below the 5% level are not indicated on the chart.

Reported Knowledge Of Alternative Energy Options

Knowledge Of Alternative Energy Options

Coupled with lower awareness around alternative energy options, BC residents also deem themselves to be less knowledgeable about these options in 2010. This is most apparent with solar energy, where almost half as many report themselves to be extremely / very knowledgeable, while a larger proportion place themselves in the somewhat knowledgeable category.

How would you assess your knowledge of…



Base All respondents familiar with alternative energy (2010 n = 737 / 2009 n = 759)

Q3: How would you assess your knowledge of the following energy sources?

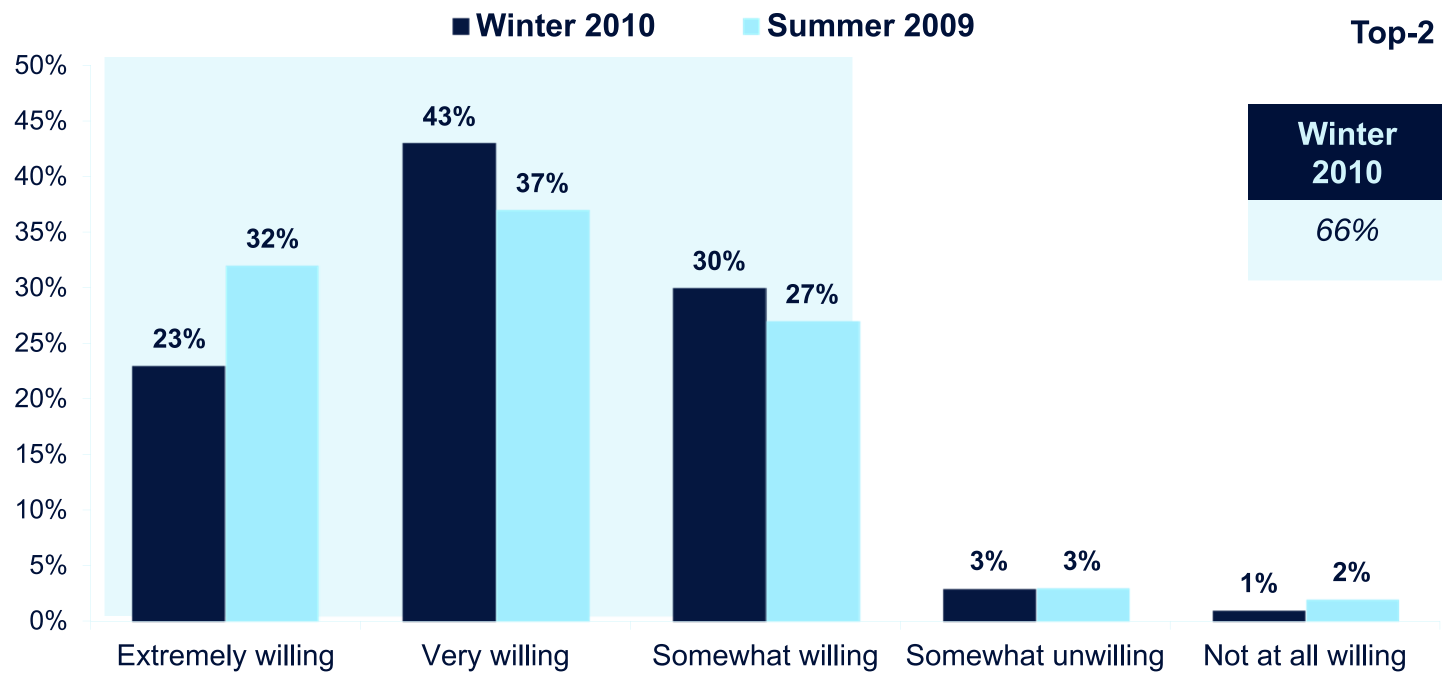
Note: Results below the 5% level are not indicated on the chart.

Attitudes Toward Alternative Energy

Attitudes Toward Alternative Energy: Willingness To Adopt

This year's results show fewer BC residents are "extremely willing" to incorporate alternative energy sources in the short term. While enthusiasm has waned slightly over the last year, overall willingness to adopt alternative energy sources remains very strong, with two-thirds being "extremely" or "very" willing. Those who are most willing to incorporate an alternative energy source are on the extreme ends of the income spectrum - those earning less than $50,000 a year and those earning more than $100,000 a year display greater willingness.

Willingness to incorporate an alternative energy source:



Top-2 Box:

Winter 2010	Summer 2009
66%	*69%*

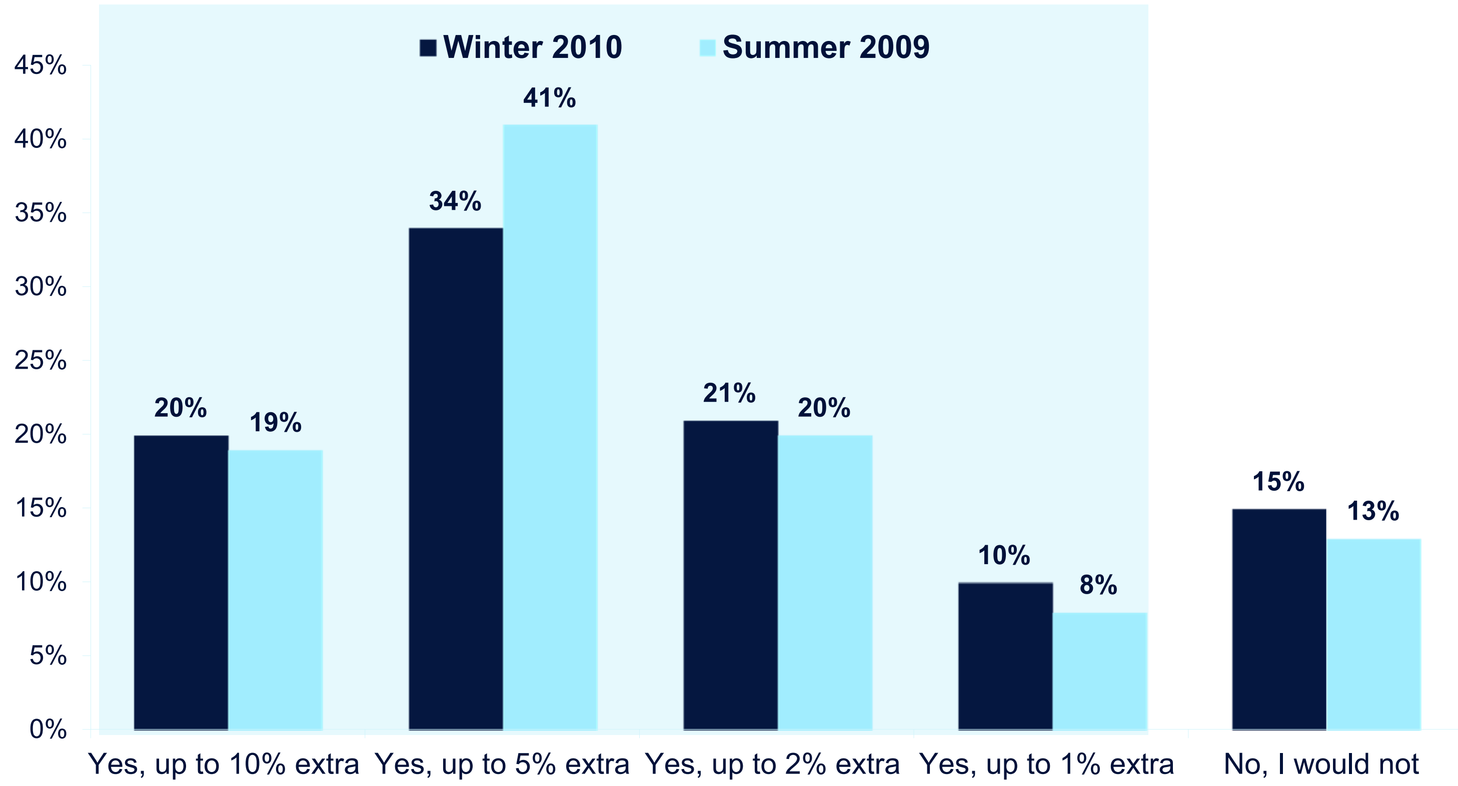
Base All respondents familiar with alternative energy (2010 n = 737 / 2009 n = 759)

Q4: If you were buying or building a new home, how willing would you be to incorporate an alternative energy source?

Attitudes Toward Alternative Energy: Willingness To Pay

Similar to 2009, the vast majority of BC residents state they are willing to pay more for a home that uses an alternative energy source. Those in the highest income bracket ($100k+) are significantly more likely to pay 5% or 10% more for a home that uses an alternative energy source. Education also plays an important role, with the college and university-educated being significantly more likely to justify paying more.

Willingness to pay extra for a home that uses an alternative energy source:



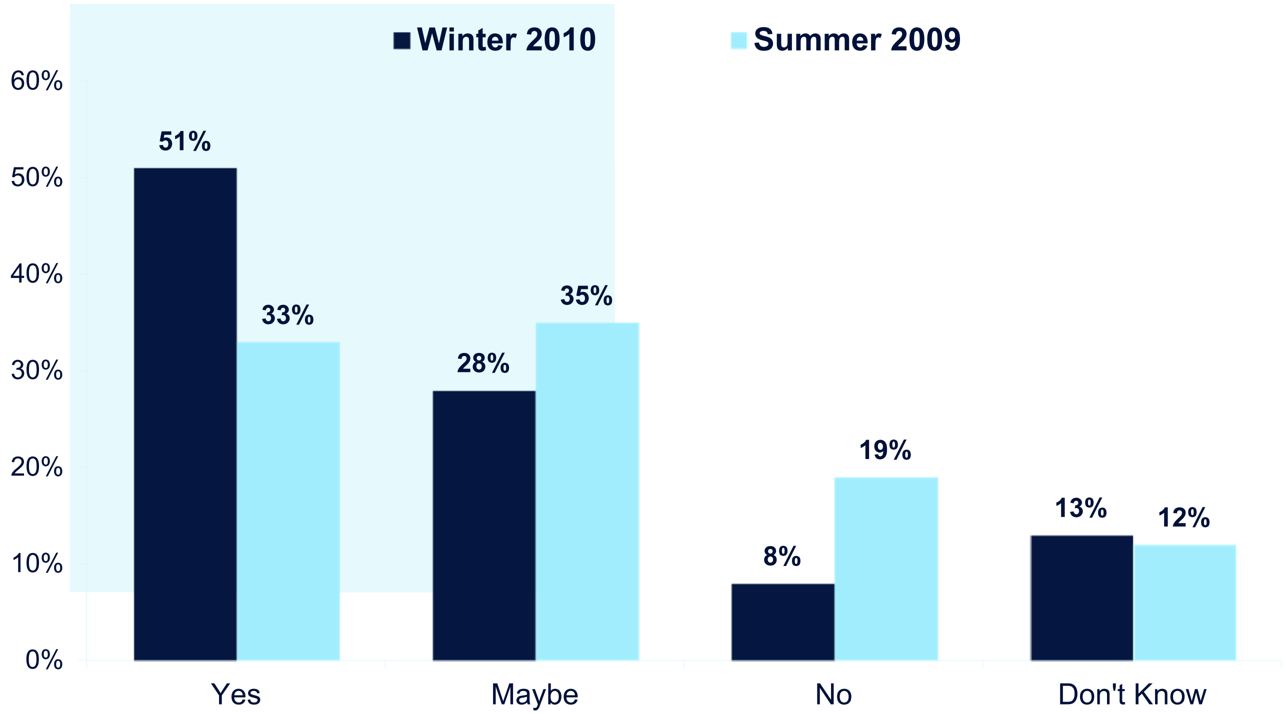
Base All Respondents willing to adopt alternative energy (2010 n = 706 / 2009 n = 728)

Q5: Would you be prepared to pay extra for a home that uses an alternative energy source?

Attitudes Toward Alternative Energy: Role Of Terasen Gas

This year, more BC residents feel strongly about Terasen's role in providing alternative energy options, with approximately half definitively believing that Terasen should provide these technologies for customers. Note that question wording was altered for 2010 to make the question clearer which may have impacted results. As in the 2009 study, support is strongest among residents in the Lower Mainland region as well as those in the18-34 year-old age group. Both segments are significantly more likely to support Terasen's role in providing these alternative energy sources.

Should Terasen Gas provide these alternative energy sources for customers?



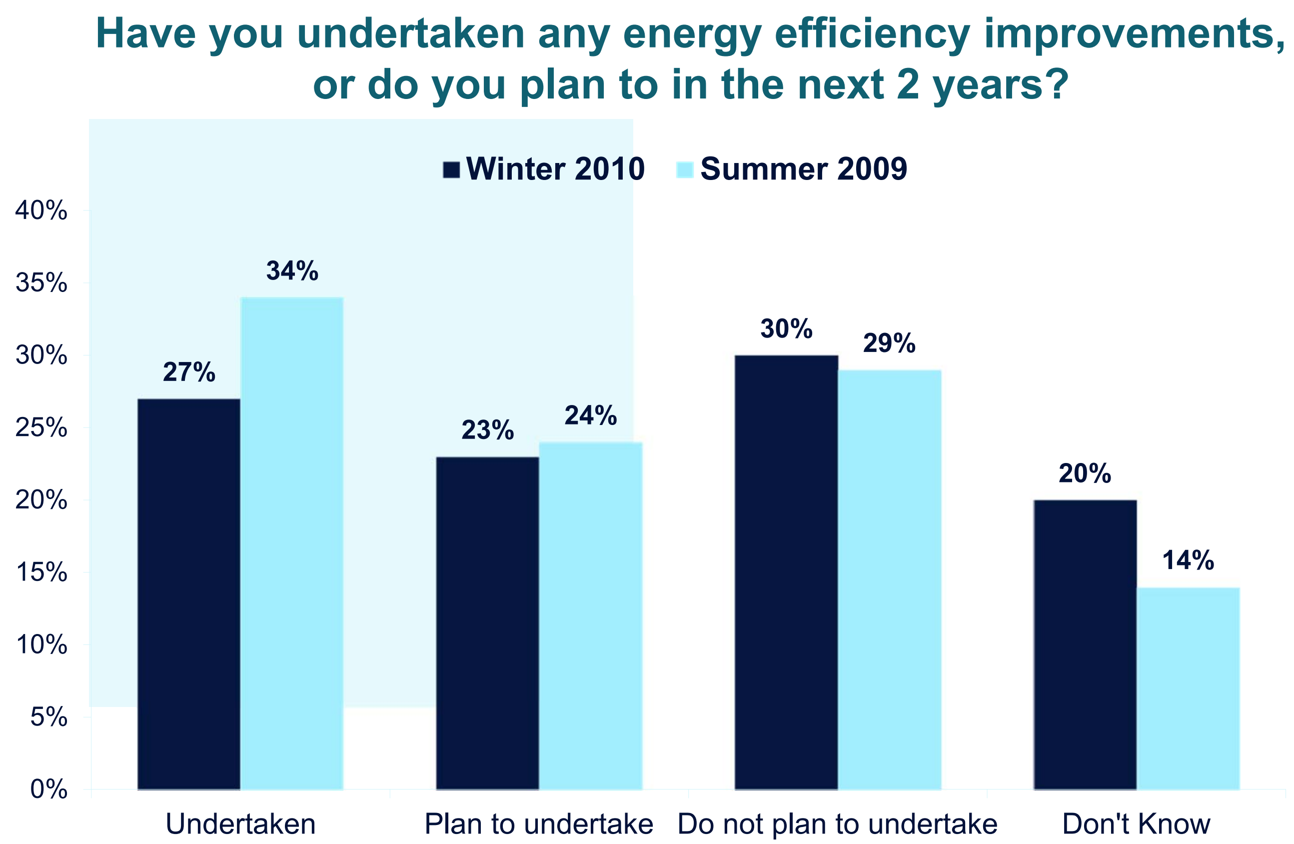
Base All respondents familiar with alternative energy (2010 n = 737 / 2009 n = 759)

Q6: Do you think Terasen Gas should provide these alternative energy sources for customers?

Note: *Question 6 is revised from 2009 when it read "Thinking of how alternative energy would be delivered to your home, do you think that Terasen Gas should provide these alternative energy sources for customers"?*

Attitudes Toward Alternative Energy: Past And Future Action

In 2010, fewer BC residents have undertaken energy efficiency improvements (27%), while more are feeling uncertain about their willingness to take action in the next two years (20%). Those in the middle income bracket are most likely to have already undertaken energy efficiency measures (33%), while those in the highest income bracket are the most likely to plan future measures (36%).



Base All Respondents (2010 n = 800 / 2009 n = 802)

Q7: Have you undertaken any energy efficiency improvements or do you plan to undertake any improvements in the next 2 years?

Appendix

Respondent Profiles: 2010 Study (1 Of 2)

Total Respondents		
Education	2010 (%)	2009 (%)
High School or less	*34%*	*38%*
Completed high school or technical school	*19%*	*20%*
Graduated from college or technical school	*22%*	*21%*
Completed some university	*9%*	*9%*
Graduated from university	*15%*	*13%*
Age	2010 (%)	2009 (%)
Under 25	*6%*	*6%*
25-34	*19%*	*20%*
35-44	*17%*	*15%*
45-54	*25%*	*23%*
55+	*34%*	*37%*

Base All Respondents (2010 n = 800 / 2009 n = 802)

Respondent Profiles: 2010 Study (2 Of 2)

Total Respondents		
Gender	2010 (%)	2009 (%)
Female	*52%*	*52%*
Male	*48%*	*48%*
Region	2010 (%)	2009 (%)
Lower Mainland	*52%*	*50%*
Vancouver Island	*18%*	*18%*
Southern Interior	*22%*	*23%*
Northern Interior	*8%*	*9%*
Income*	2010 (%)	2009 (%)
Under $50,000	*33%*	*33%*
$50,000 – just under $100,000	*37%*	*37%*
Greater than $100,000	*16%*	*16%*
Undisclosed	*14%*	*14%*

Base All Respondents (2010 n = 800 / 2009 n = 802)

Note * 2010 income proportions are based on 2009 proportions levels. Income is household income, pre-tax.

Alternative Energy

In-Depth Interview Summary

January 14, 2011
R1707

Presented to:
Terasen Gas

infocanada@tns-global.com
www.tns-global.com

Contents

At TNS, we know that being successful in today's dynamic global environment requires more understanding, clearer direction and greater certainty than ever before. While accurate information is the foundation of our business, we focus our expertise, services and resources to give you greater insight into your customers' behavior and needs.

Our integrated, consultative approach reveals answers beyond the obvious, so you understand what is happening today – and what will happen tomorrow. That is what sets TNS apart.

Thank you for allowing us to explore your business needs. We hope you will continue to trust TNS to provide the insight you need to sharpen your competitive edge.

Appendix

Executive Summary & Strategic Implications

The following summary and recommendations are based on a series of confidential in-depth interviews conducted by TNS Canadian Facts on behalf of Terasen Gas. The topic of the interviews was the acceptance and use of alternative heat sources (e.g., biomass, geothermal, waste heat recapture, etc.). The interviews were conducted with elected officials, developers and industrial plant operators throughout British Columbia. The interviews took place between December 1 and December 22, 2010 and lasted approximately forty-five minutes each. All interviews were done by Raymond Gee, Research Director, TNS Canadian Facts.

Executive Summary

Awareness and opinions about alternative energy systems have not changed significantly since this research study was last conducted in the summer of 2009.

The Market Is Keen On Alternative Energies

All respondents are concerned they do not have the knowledge to properly decide on the energy options that are the most financially practical, environmentally friendly and technically reliable. The upfront costs associated with new technologies also continue to be a concern. However, these concerns are not deterring respondents from wanting to evaluate the merits of alternative energies. All respondents believe alternative energies are becoming more mainstream, and that upfront costs will continue to come down over time. They agree on the positive potential of alternative energies to tap into sustainable energy options and lower operational energy costs.

A Leader Is Still Required

However, there remains no identifiable leader(s) in the alternative energy market that companies can reference for more information, or input into the design of a new alternative energy system. The Government is also looking for the same information as Developers and Industrial Operators. Most respondents still believe that legislation is not the answer, and want someone to take the lead in instituting such change.

Terasen Can Play A Large Role In This New Market

Respondents hold positive impressions of Terasen and see alternative energies as a natural extension for the organization. Terasen is believed to have the financial resources, expertise and track record to assume a central role in this market. Therefore, the organization is seen as a positive fit to promote and sell alternative energy solutions. The one concern with Terasen entering this market is the fear that it might not provide competitive pricing if it commands a monopoly.

Recommendations

Our recommendations for Terasen remain similar to those made in 2009. They include:

1. *Develop a broad strategy that will motivate governments of all levels to adopt alternative energy policies and practices.* Provincial policy and civic strategy are already making a difference in the adoption of alternative energy systems. There just needs to be more uniform policies from local government.

2. *Help Government, Developers and Industrial Operators understand the pricing structure for the main alternative energy systems.* Help respondents understand the pay-back period to recover their investments. Also, consider developing rebates and financial incentives for those who decide to install an alternative energy system.

3. *Generate better 'top-of-mind' awareness for heat delivery in general and alternative energies specifically.* Provide more information on the technologies associated with alternative energy. All respondents want more, and better, information to make alternative energy decisions.

Foreword

Background

Terasen commissioned this research to learn about customer views on providing alternative and integrated energy systems.

Objectives

Specifically, this study addresses the following objectives:

- Measure the level of respondent awareness of, and knowledge about, integrated and alternate energy solutions among key members of the target market;
- Assess interest in Terasen's participation in providing alternative energy technology solutions;
- Identify key drivers and barriers to alternative energy solutions;
- Explore the value target market members place on integrated and alternate energy;

Research Methodology

TNS Canadian Facts conducted fourteen in-depth interviews (IDI's) to discuss the research objectives. Survey research will likely be required later on to quantify opinions and attitudes but these interviews were designed to explore the range of issues and opinions on this topic.

Each IDI session lasted approximately forty-five minutes in length and was conducted by an experienced, senior interviewer. Respondents were identified as individuals who influence energy purchase decisions. The format was:

Target	Quantity
Elected Municipal Representatives	3
Builders, Developers	7
Industrial Operators	4
Total Interviews	**14**

TNS Canadian Facts, using our in-house services, recruited all respondents. They were offered a $100 incentive as a thank-you for participating and given the choice of taking the incentive or donating it to a charity of their choice. Eight of the 14 interviews were individuals that participated in the research last year, which enabled us to probe into how the opinions and knowledge of the topic areas may have changed in that time.

The interviews were conducted between December 1 and Dec 22, 2010. All interviews took place through teleconference.

Note of Caution

Please bear in mind the clearly qualitative nature of this phase of the research study. These findings are not quantitative conclusions, but rather the qualitative insights of the interviewer based on the response of a limited sample. They are not statistically valid unless quantified by more rigorous population sampling techniques.

January 2011

Key Findings

The results of the research are presented under the following main headings:

- Perspective on Respondents;
- Terasen's role in providing alternative energy products and services;
- Respondent awareness of alternative energy forms;
- The value respondents place on alternative energies;
- The level and type of "push" that respondents feel in moving to alternative energy;
- The drivers and barriers associated with converting to alternative energies; and,
- Appendix
  - Recruiting Questionnaire
  - Discussion Guide

Perspective On Respondents

Interviews were conducted with three main groups:

- Elected Municipal Representatives;
- Real Estate Developers; and,
- Industrial Operations.

The views of these three groups have not changed drastically since the last measure in the summer of 2008.

Elected Representatives

All elected representatives understood the need and inevitability of alternative energy solutions, and many municipalities are exploring alternative energies as a way of re-using many of the resources they already have, as a way of reducing reliance on their current energy sources. The mayors we spoke to indicated that their municipalities are actively engaging organizations, such as Terasen, for more information on how they can incorporate various forms of alternative energies into their planning.

Two primary concerns from the mayors we spoke to revolved around information needs:

1. They indicated that they would like to have more information around alternative energy choices; and,

2. The implementation of changes in heat-delivery.

While no one reported any significant "push" to adopt alternative energy solutions, the current environment is one in which these elected officials, on a personal level, feel that it is their duty to explore their energy options.

Although the up-front costs of adoption continue to be a barrier, there is optimism that municipalities could form partnerships to help spread the initial investment in any such project.

Developers

Real estate developers continue to be the group that lacks the most knowledge about alternative energies. They are less knowledgeable about alternative energies available, and their awareness of the technologies appears to be based on current projects using alternative energy solutions. Their concerns remain centered around up-front costs, how to integrate alternative energy solutions and how the technologies would perform for their clients.

Developers feel there is currently a low appetite for alternative energy solutions, and many look to municipal government to push some of these technologies. However, this group continues to be wary of government red-tape around the topic. Nevertheless, the consensus is that with the BC economy still rebounding, and the housing market in a slump, there is less demand from the end consumer to spend more for alternative energy solutions.

Industrial Operators

Most respondents in this category are professionals or plant engineers from firms that consume large quantities of natural gas or electricity. This group is most knowledgeable about alternative energy solutions and the majority revealed that they are continually evaluating different heating options as a way to reduce their operating costs. For each alternative energy technology, these respondents wanted to know the operating costs, performance and the reliability of the solution.

As indicated in the report last year, industrial operators are most pragmatic in seeking firm answers to technical questions.

Terasen's Role

Respondents were asked if Terasen has a role to play in planning for, and promoting the use of, alternative energy systems and the technologies that deliver heat. Last year all respondents agreed that Terasen should seriously consider such options because it has an obligation to do so. This remains the overwhelming sentiment as respondents see a large upside to having Terasen play a role in this new market.

Reasons For Support

Last year, respondents pointed to the following reasons Terasen should move into this area:

- As a reliable deliverer of heating fuel to British Columbia, Terasen has the expertise, infrastructure and credibility to move into this area;
- Terasen has a long history in BC and has the resources necessary to ensure long-term reliability of any alternative energy project or installation. At the same time, Terasen could form effective partnerships with municipalities and large industrial operations that would benefit both; and,
- The alternative energy concept is a natural extension of Terasen's current brand and operations.

This year, respondents added the following factors for Terasen to be involved:

- Terasen is trusted in the community with a positive reputation. It is also closely regulated. There is the perception that, compared to private firms, they will listen to and consider the views of constituents in its decisions.
- Several respondents stated bluntly they would prefer to work with Terasen than other energy providers based on their current experiences – they indicated that Terasen seemed more impartial and responsive to their queries.

Reasons Against Support

When asked for reasons why Terasen should not move into the field of alternative energies, respondents again did not offer many reasons against. Some of the reasons repeated from last year include:

- Terasen could have a monopoly on the alternative energy market, and therefore, not provide consumers with real choice or competitive prices; and,

- The costs for research and development would be passed on to consumers through rate increases.

Other negative factors regarding Terasen moving into this market, from this year's interviews, include:

- Terasen is a large organization. Their control of the alternative energy market could mean high rates and slow service, because of high amounts of administration; and,

- Terasen's infrastructure is not built to support alternative energy sources. The organization should stick to what it does well.

Roles For Terasen

One of the important roles that respondents want Terasen to play in this emerging market is that of an educator. Most respondents require more information about alternative energy systems in order to make informed decisions about their energy options, and view Terasen as a credible source for this information. Some developers would like to see this role extended further, providing informative material to the end consumer.

Each respondent group prefers different channels for learning about alternative energy systems. For example:

- Mayors would like to set up one-on-one meetings with their staff on the technical aspects. However, they would prefer to participate in non-partisan discussions or workshops which cover alternative energy options in a less technical manner, for politicians instead of planners. For an elected official, their main interest is in understanding which options are most practical and which ones are the most environmentally friendly.

- Industrial Operators prefer in-person meetings to learn more about alternative energy so they can ask questions. This group is looking for hard numbers. They want to understand the operating costs and whether the system performance can meet their needs. They also want to see diagrams to understand the installation requirements.

- Developers indicated that they are best reached via UDI meetings or other professional conferences. This group is interested in seeing case studies or actual projects in which an alternative energy system has been successfully implemented. In addition, they want to understand where the energy comes from, pricing structure and worst-case scenarios.

Awareness Of Alternative Energies

Respondents were asked to list any alternative energy sources they were aware of followed by a prompted list of other sources not mentioned. Recall of these energy sources have not changed since last year.

The most top-of-mind energy sources volunteered are:

- Geothermal;
- Wind; and,
- Solar.

Less likely to be mentioned sources:

- Biogas;
- Sewage Heat Recapture;
- Waste Heat Recapture;
- Biomass; and,
- Heat pumps.

District Energy Systems

For the second year, District Energy Systems (DES) were never identified as an alternative energy source, but most said that they knew of these systems, once the concept was explained. Some even cited projects in which they believed such systems were currently used.

Geography

Geography plays an important role in which alternative energies a respondent is aware of and which ones they find appealing. Last year it was indicated that respondents from BC's interior were more likely to be aware of solar as an alternative, whereas those from areas where logging plays a major economic role were quick to report biomass as a viable solution. Similarly this year, agriculture-heavy regions gravitated towards sewage and waste heat recapture solutions.

Value of Alternative Energies

The merits of alternative energies in terms of sustainability, reliability and costs are covered in this next section.

Sustainable Energy

No one will disagree that the main benefit of developing alternative energies is so that the consumption of non-renewable resources can eventually be replaced with the use of sustainable resources. Civic leaders believe it is their responsibility to preserve their community's environment. To the credit of these elected officials, Developers have pointed to government initiatives and/or requirements (e.g., Green Building Regulations from the provincial Government) as the driving force behind many of the alternative energy projects they are involved in. For one Industrial Operator, their organization has sustainability and GHG reduction targets, through the Ministry of Environment.

All three groups cite numerous social and ethical reasons for using alternative energy sources, however Developers and Industrial Operators were more cautious about supporting these systems due to the higher costs involved.

Price Fluctuations Less Of A Factor

Last year, respondents believed that localized energy sources would mitigate price fluctuations often seen with natural gas. Industrial respondents, in particular, like this because it stabilizes their monthly energy bills. While these views have not changed, respondents this year were more concerned with the large initial investment costs associated with installing an alternative energy system, and the amount of time it would take to recover such costs.

Inevitability

Once again, most respondents agree that alternative energies as unavoidable – current energies such as natural gas will eventually run out and greener energies will grow in demand by consumers, once their price decreases to more affordable levels.

Making A Decision On Which To Use

This year, each respondent group held a different view on which alternative energy is best for them. Elected representatives readily admitted that they do not have enough information to decide which alternative energy is best for their community – nor do their staff. Two of the mayors we spoke to indicated that they have invited Terasen to discussions about the prospects of an alternative energy project in their municipality.

Meanwhile, for Developers, they prefer to deal with the technologies that are proven and working in the market place. At this point in time, several Developers identified geothermal as the most “mainstream” of the alternative energies for heating homes. Therefore, there is a stronger preference for a geothermal solution, because it is more established than the other energy forms. Developers also mentioned solar power as a popular source for powering electronics, although one Developer raised concerns about the environmental impact around the disposal of the batteries in these systems.

Industrial Operators approached choices with a more objective mindset, preferring to reserve their opinions until they can compare each technology on its performance, efficiency and cost.

The Players In The Market

When asked what competitors come to mind in implementing alternative energy solutions, respondents were again hard-pressed to come up with specific companies. Terasen Gas and BC Hydro were the most consistently-mentioned organizations. A few companies specializing in geothermal or solar power were also mentioned, but most respondents could not identify any such companies.

The “Push”

Most respondents do not feel any “push” to implement alternative energy solutions. Developers believe that the price-tags associated with these solutions and the state of the economy may be responsible for the lack of demand. Some feel that there was a stronger push from the end consumer a few years ago for alternative energy systems, when the housing market was in boom times.

The Media And Public Opinion

Last year, elected representatives cited the media as leaders in creating an impetus for using alternative energies. However, there were no mentions of media influence this year. The only pressures for change reported by elected representatives this year stem from small groups of environmentalist. However, elected representatives admitted that these pressures had little influence on the decisions they made.

Municipal Requirements

As mentioned previously in this report, Developers feel the “push” from government more than any other group in the market. There were two different instances illustrated:

- One Developer complained that B.C.’s political landscape does not have a uniform policy on energy. They felt it was unfair that one municipality required them to install geothermal solution, but a similar townhouse project in an adjacent city did not.

- Another Developer expects alternative energy solutions to be more prominent because their local building codes are changing. They indicated that their local government is going to require that new houses be *energy cleaner* (e.g. every house needs to have a grey water system).

Drivers And Barriers

Respondents feel that alternative energy solutions are slowly making headway into the BC market. Most would agree (like last year) that a combination of legislation and reduced up-front costs will speed up the adoption of these systems in the market.

Key Drivers

Cost Savings

Some respondents view alternative energies as a means to lower long-term operational costs, particularly in the case of geothermal heating and solar power. They said that the heat would always be there, therefore fuel no longer has to be brought in (through pipelines or other means) and commodity price fluctuations are therefore avoided. As one mayor indicated, “The upfront costs may be high, but the savings will grow over time.”

Positive Reputation And Image

Respondents continue to hold the perception that using alternative energies promotes a positive image. For example, one developer revealed that many building owners want to appear as socially and environmentally responsible. They note that even private owners (i.e., of condominiums, office centres and shopping centres) want to promote greener buildings; it could be turned into a competitive advantage. One of the ways to do this is to install alternative energy systems in buildings.

Barriers

Upfront Costs

Upfront investment costs continue to be the most frequently mentioned barrier to implementation. However, many respondents reported that these costs are coming down and will eventually become viable alternatives. Nevertheless, developers would pass the costs for alternative energy directly onto purchasers who want the systems, so it’s less of a concern for them. Meanwhile, the elected representatives, who are enthusiastic about alternative energies, rationalize that upfront costs will be recovered over time through lower operational costs.

One respondent mentioned program or rebate incentives as a way to overcome these upfront costs.

Lack Of Knowledge

Respondents continue to say that they do not know enough about alternative energies to make informed decisions. They also point out that governments and Terasen do not have the information they are looking for too.

Red Tape

One of the new barriers identified in the research this year is red tape. A Developer in the Interior pointed out that local industry wants to do use alternative energies more, but there are too many roadblocks in the form of red tape from local officials.

Not Appropriate For All Projects

Another newly-mentioned obstacle by Developers is the number of projects that they would consider using alternative energy systems for. Some respondents believe that bigger projects are more ideal for integrated alternative energy solutions. In larger projects they have the ability to separate the energy sources to heat different individual units (e.g., geothermal to heat the hall-ways, solar power to heat the common hot water tank). For smaller projects, this does not make as much economic sense.

Appendix

- Recruitment Screener
- Discussion Guide

1140 W. Pender Street
Suite 610
Vancouver, British Columbia V6E 4A1

Tel: (604) 668-3344
Fax: (604) 668-3333
infocanada@tns-global.com

www.tns-global.com

TERASEN GAS ALTERNATIVE ENERGY INTERVIEWS
R1707

NAME :____

ORGANIZATION: ____

HOME PHONE :____

BUSINESS PHONE :____

CELL PHONE:____

E-MAIL:____

RECRUITER:_______________________________

RECRUIT ACCORDING TO THE FOLLOWING SPECIFICATIONS:

Target Quotas	Quantity
Elected Representative	4
Developers	6
Industrial	4
Total Interviews	**14**

LOCATE APPROPRIATE INDIVIDUAL AND INTRODUCE:

Hello, may I speak to __________ [NAME FROM LIST]? My name is __________ and I am calling from TNS Canadian Facts, a professional market research firm in Vancouver, on behalf of Terasen Gas. Currently Terasen Gas is looking for qualified people to participate in confidential interviews about your opinions on alternative energy.

The interview will last about 30 to 45 minutes and can take place either over the telephone or in person. The discussion is confidential and as such, your identity will remain anonymous in any reporting to Terasen Gas.

As a thank you for your time, we will donate $100 on your behalf to a charity of your choice (you will receive the tax receipt).

Let me assure you that this project is being conducted for research purposes only, and that no one will try to sell you anything.

PERSUADERS [IF NECESSARY]:

- We are undertaking this study rather than Terasen Gas to maintain strict confidentiality for your responses. We will report the responses back to Terasen without identifying who said them.
- You are welcome to call the project manager, Raymond Gee at 604.668.3311.
- The interview is part of on-going research to improve services for customers.
- We are not selling anything at all. Terasen will use your responses to improve its services. Your number was selected randomly from a list provided by Terasen Gas.

Q: How did you get my information?

A: Your name and phone number were randomly chosen from a list of people provided by Terasen Gas as we are conducting this work on their behalf. Participation in this study is completely voluntary.

Q1. Region (**FROM LIST – AIM FOR A GOOD MIX**)

____

Q2. Target Group (**OBSERVE TARGET QUOTAS**)

____

Q2. May we ask you a couple of questions to see if you might participate?

Yes ....1 **CONTINUE**
No...2 **TERMINATE**

GENDER: (**OBSERVE**): Male
Female

Q3a. **IF RESPONDENT IS AN ELECTED REPRSENTATIVE, GO TO INVITATION.**

Q3b. **IF RESPONDENT IS A <u>BUILDER/DEVELOPER/ARCHITECT</u>, ASK:**

If a decision had to be made regarding the choice of heating systems or technologies going into a new building, would you have influence, even in part, on that decision?

Yes	**CONTINUE (SKIP TO INVITATION)**
No	**GO TO Q4**
Not Sure	**GO TO Q4**
Don't Know	**GO TO Q4**

Q3c. **IF RESPONDENT IS A <u>TERASEN COMMERCIAL CUSTOMER</u>, ASK:**

If a decision had to be made regarding the choice of heating fuels or technologies in an existing building, would you have influence, even in part, on that decision?

Yes	**CONTINUE (SKIP TO INVITATION)**
No	**GO TO Q4**
Not Sure	**GO TO Q4**
Don't Know	**GO TO Q4**

Q4. Can you think of the person who would have influence on that decision that you could put us in touch with?

Yes **OBTAIN NAME, CONTACT THAT PERSON AND RESTART INTERVIEW**

____

No/Not willing to provide	**THANK AND TERMINATE**
Don't Know	**THANK AND TERMINATE**

Invitation to Interview Session

IDENTIFY CONVENIENT DATE AND TIME FOR INTERVIEW. NON-STANDARD BUSINESS HOURS ARE OKAY (i.e. earlier than 9AM and later than 5PM but not after 7:00PM)

Date: _______________ Time: __________________________

Thank you. We will call you the day before to reconfirm the appointment.

In appreciation for your participation, you will receive a $100 honorarium or we can donate it directly to your favourite charity. To whom should we make the cheque payable and where should it be sent?

RECORD NAME AND ADDRESS OF RECIPIENT. IF RESPONDENT DOES NOT KNOW THE ADDRESS OF THE CHARITY, TELL HIM OR HER THAT WE WILL LOOK IT UP FOR THEM.

Cheque payable to: ____

Address: ____

Your interview will take place on:

RESTATE DATE AND TIME FROM ABOVE

If you cannot attend for any reason, please call (1) 604.668.3325 and leave a message.

Terasen Gas
R1524: Alternative Energy Interviews
Discussion Guide – FINAL
July 27, 2009

1) **Introduction**
   a) Assurance of confidentiality, confirmation of incentive distribution.
   b) Interview procedures, etc.
   c) Questions for interviewer
2) **Awareness**
   a) What kinds of alternative energy sources are you aware of (all forms)?
   b) What kinds of alternative sources are you aware of that deliver direct heat (*IF NECESSARY, CLARIFY BETWEEN HEAT ALTERNATIVES VS. ELECTRICAL*)?
      i) Probe for:
         (1) District Energy Systems –
            (a) Biomass
            (b) Sewage heat recapture
            (c) Waste heat recapture
         (2) Geothermal
         (3) Solar
         (4) Biogas –sewage and agricultural gas capture (secondary)
         (5) NGV (secondary)
3) **Value**
   a) Of all the individual alternative energy sources, which ones:
      i) Sound most interesting? Least interesting? Why?
      ii) Most practical (cost and otherwise)
   b) Where, or in what situations would you put in alternative energies? Which ones? Why?
   c) How much “push” are you feeling to implement alternative energy sources of all kinds? Of heat alternatives only? Is there a difference? How?
   d) Where is the “push” coming from? *PROBE FOR*:
      i) Legislation or policy(including GHG targets)
      ii) General public
      iii) Clients (professionals and developers only)
      iv) Energy cost reduction initiatives
   e) What would motivate you to implement an alternative energy solution? *IF NECESSARY, PROMPT ON*:
      i) Avoiding spot price fluctuations
      ii) GHG reduction and targets
      iii) Presence of existing incentive programs (if so which ones?)
      iv) Positive public recognition
   f) What are the barriers to implementing alternative energy solutions and integrated heat solutions? *PROBES*:
      i) Initial costs
      ii) Higher ongoing fuel/energy costs

iii) Perceived reliability of alternative energy sources

4) Demand

a) What level of demand exists for integrated solutions?

b) How will demand change/not change in the future? For what reasons?

c) What needs to happen or change for alternative heat sources/integrated systems to improve demand? *PROBES*:

i) Costs
ii) Legislation
iii) Technology
iv) Public perceptions
v) Customer locations (geothermal and solar only)

5) Terasen's Role

a) Which other options come to mind when talking about alternative energy solutions? Does Terasen have role in this? How?

b) What are the "upsides" of Terasen providing these services? The downsides? Be as specific as possible.

6) Information Needs

a) What do you need to know about this idea? What should Terasen be telling you about it?

b) What are the key topics that they need to address? Why?

c) What are the best ways to reach you with information?

7) Summary

a) Thinking about our entire discussion today, what are the two main points that you think Terasen needs to know? Why those ones?

b) Thank you.

Biogas Study

Terasen Gas

March 2010

Table Of Contents

Forward

BACKGROUND

There are two major changes stirring within the energy sector: (1) the marketplace is becoming more competitive, and (2) the importance of environmental issues appears to be increasingly relevant to energy consumers. Being faced with these changes, Terasen Gas (Terasen) is repositioning itself as a diverse energy solutions provider that can be both competitive and environmentally friendly (i.e., by minimizing the environmental impact of its activities).

As part of this new positioning, Terasen is exploring a *biogas* program that offers green energy choices based around biomethane fuels.

TNS was commissioned to help Terasen better understand the potential market for biogas, its market drivers and other factors affecting different price points. Specifically, the objectives of this research are to measure:

1. Market interest, the potential target market and market size for a renewable energy program;
2. Market interest and the potential target market for a carbon offset program;
3. Market drivers;
4. Price points and factors affecting price points; and,
5. Customer perceptions of different product offerings.

This study features:

- A discrete choice analysis; and,
- Conversion Model™ analysis.

Forward (cont'd)

METHODOLOGY

Interviews were conducted with both BC households and businesses. A total of 1,401 online surveys was conducted between November 23 and December 4, 2009 among BC residents (18 years of age or older) using TNS Canadian Facts' online panel. TNS online panels are comprised of individuals who volunteer to complete surveys from time to time.

Three different types of residential households sampled.

- Terasen Gas customers (those who receive a gas bill directly from Terasen);
- Indirect customers (gas users who are not billed directly i.e. gas costs are included in strata fees or rent); and,
- Non gas users (those who do not use gas).

In addition to these residential interviews, 500 interviews were conducted with business customers of Terasen. The business sample was provided directly from Terasen.

An online methodology was used into order to facilitate a discrete choice analysis – which cannot be done on the telephone or by mail back. The questionnaire was developed by TNS in consultation with Terasen. Commercial customers were contacted initially by telephone and those which choose to participate were then emailed a link to the online survey.

Forward (cont'd)

METHODOLOGY (cont'd)

The results of this study are unweighted. Therefore, when reviewing results on a total basis, it is important to keep in mind how the sample breaks down with respect to the above three types of households.

Sample Composition

	Actual Interviews	Proportion of Total
	#	#
Residential Study		
Terasen Gas customers (receive gas bill directly from TG)	799	57%
Indirect customers (pay gas bill indirectly through rent or strata fees)	200	14%
Non-customers (does not use gas at home)	352	25%
Residents who don't know their energy source	50	4%
Total Residential Interviews	1,401	100%
Business Study		
Total number of interviews	500	100%

Executive Summary

Executive Summary

Both the residential and commercial customer studies produced results that lead to similar recommendations for Terasen. This is not all that surprising since commercial organizations are managed by individuals, whose philosophies, attitudes and personal experiences become part of the organization's corporate culture.

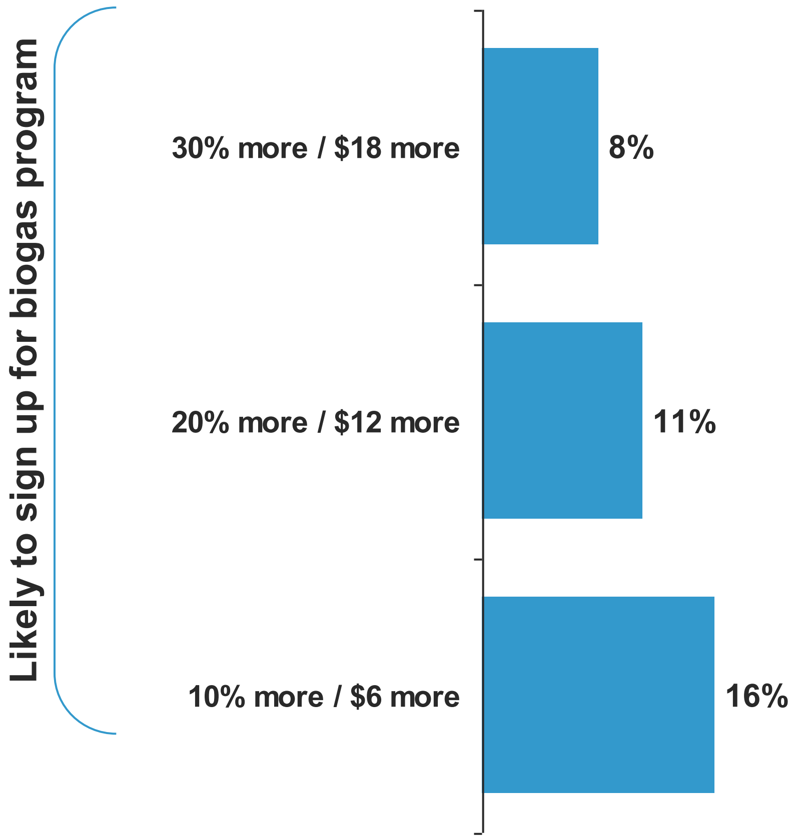
Most BC residents and commercial customers have taken energy saving actions in the past, so they should be open-minded to new, environmentally-friendly energy initiatives. In this study, two different types of initiatives were presented to residents: a renewable energy program and a carbon offset program. Both stakeholder groups confirmed at different points in the study that they are more likely to sign up for a renewable energy program (mainly biogas) than for a carbon offset program. If Terasen were to offer only one of these options to market, we would recommend a biogas program since it will yield a larger market share.

If all factors today remained constant (e.g., energy prices remain unchanged), 56% of Terasen's residential customers and 47% of commercial customers would sign up for a biogas program on the benefits of the fuel alone. However, this potential market will decline if the price of the program increases their gas bill. Price is one of the main barriers to a biogas program for many residents and businesses. It restrains many residents and commercial customers from committing to the program. Almost one-quarter of Terasen's residential customers and one-third of commercial customers will shun the idea, even if there is a negligible price increase of up to 1% for everyone. These figures climb up to nearly 40% (residential) and 56% (commercial) with a 3% universal price increase. The best case market share projections for Terasen residential and commercial customers at different price levels are laid out in the following three pages.

Residential customers are more enthusiastic about signing up for a biogas program than commercial customers. There appears to be greater hesitation on the part of commercial customers. This fact, coupled with the larger residential market, makes residential households a potentially more lucrative segment to target (than commercial customers).

Executive Summary (cont'd)

Terasen Residential Customers

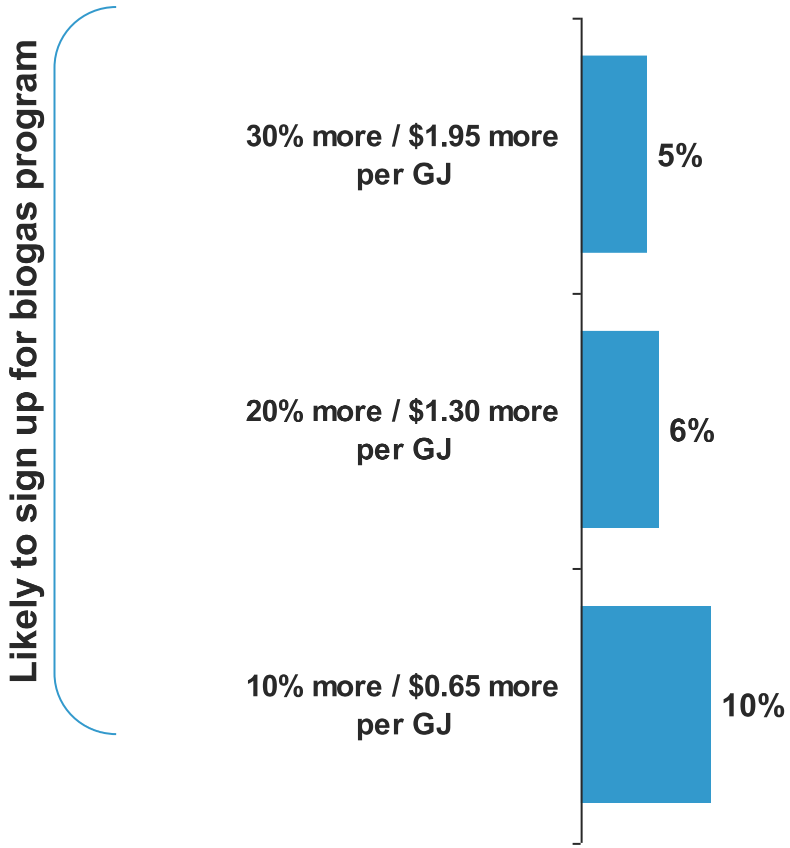


Note: Based on share of preference. With GHG reductions factored in.

Percent of Residential Customers That Would Subscribe To Biogas Program

Executive Summary (cont'd)

Terasen Commercial Customers

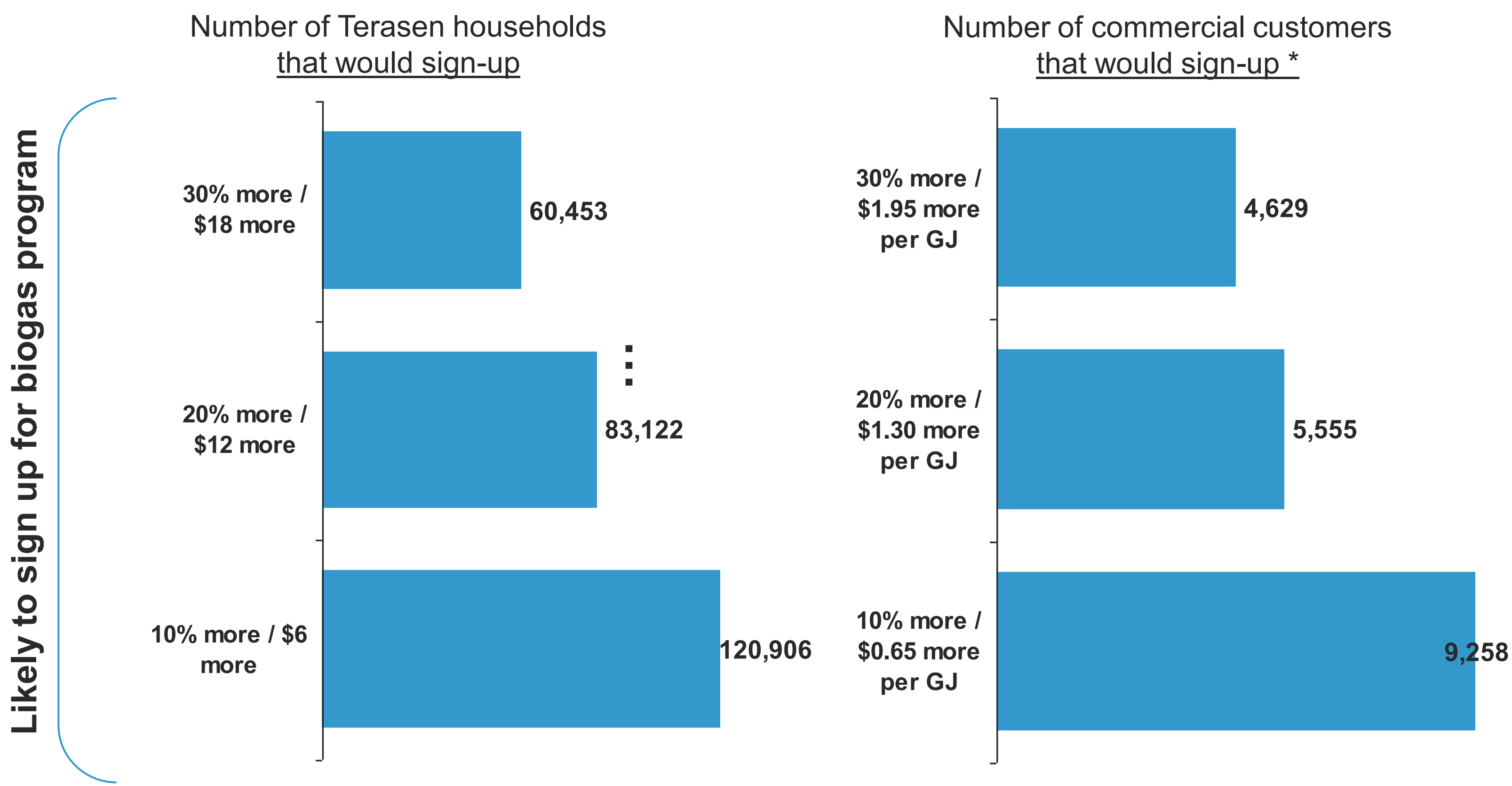


Note: Based on share of preference. With GHG reductions factored in.

Percent of Terasen <u>Commercial</u> Customers That Would Subscribe To Biogas Program

Executive Summary (cont'd)

Using these rough market projections and Terasen's customer count data it is possible to get an idea on how many residential households might potentially subscribe to a biogas.



Number of Terasen Gas households That Would Subscribe To Biogas Program

Executive Summary (cont'd)

The decision on what price point to introduce a biogas program at will depend on Terasen's goals:

- To maximize household and business involvement, introduce universal price increases borne by all customers;
- To maximize household and customer involvement with premium pricing, increase current prices by 10%;
- To balance GHG reductions with premium pricing; increase current prices by 20%; and,
- To offer higher GHG reductions, higher price increases of 30% (or more) will be required.

With respect to the potential target segments for a biogas program, we recommend designing a communications strategy aimed at residential households first. On the residential side Terasen should target:

- Higher educated and higher income households (they tend to be less price sensitive);
- Females (the tend to be more green); and,
- Those who have participated in past energy savings programs.

Separate communications should be sent to commercial customers. However, it is much more difficult to target this group. There are no definitive firmographic variables that easily identify a green organization from one that is less green or brown. A more universal communications strategy might be needed with commercial customers.

Sign up rates for a biogas program will depend on the strengths of Terasen's communications and marketing. First, as illustrated in a trade-off analysis, the marketing campaign must demonstrate the environmental benefits of biogas and how it reduces greenhouse gas emissions. The level of greenhouse gas reductions associated with a program has a strong influence on which programs customers will support. This is particularly true for commercial customers, who would like to support programs that offer higher GHG reductions (of 30% or more).

Second, the marketing campaign must demonstrate environmental value for the price paid. Customers will want to see how much their carbon footprint is being reduced, for each dollar extra that they spend. Terasen might consider updating its current billing template to incorporate this additional information.

Executive Summary (cont'd)

We recommend Terasen proceed with a biogas program for another important reason. Doing so will improve perceptions of the organization's role in the community, care for the environment and investment in environmentally-friendly technologies. In other words, it will improve Terasen's corporate image. This will also aid in re-positioning Terasen as a diverse energy solutions provider that is both competitive and environmentally friendly to both BC residents and the business community.

General Summary Of Findings

About This Report

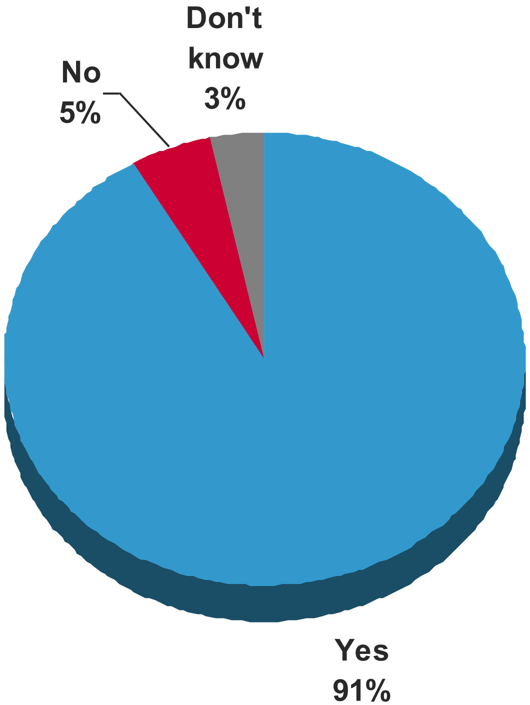
The findings contained in this report are sourced from two different studies that use a similar questionnaire. We have separated the detailed findings of this report into two sections – the first for BC residents and the second section for commercial customers. Because the two customer groups are distinct, we have not amalgamated their data together into one group for analysis. Where relevant, we have included commentary in the business customer section as to how the two groups are similar or different.

Residential Customer Findings

Energy Conservation

The majority of BC residents report having taken conservation measures in their homes. These measures vary, but the most common actions include the 3R's, energy efficient lighting and reduced water use. Clearly, conservation programs have had a wide reaching influence in this province over the years. Because this audience already buys into the benefits of conservation, they should be receptive to new programs with similar intentions.

Whether Steps Taken To Save Energy



Base: Total respondents (n=1,401)

Steps Taken To Save Energy At Home

	Total
Base: Total respondents who have taken steps to save energy at home	(1,280)
Re-using / reducing / recycling materials	88%
Energy efficient lighting	84%
Reduced water use (e.g., low flow showerheads)	69%
Weather stripping / caulking	54%
Insulating windows / doors / spaces	47%
Installed a programmable thermostat	36%
Installed timers for lighting	22%
Replaced existing furnace with a high-efficiency furnace	19%
Alternative energy sources (e.g., heat pumps, solar panels)	9%
Lower Heating / Turn Off / Down Thermostat	3%

QG1: Have you taken steps to save energy in your home?
QG2: What steps have you taken to save energy in your home? (select all that apply)

Reasons For Not Taking Steps To Save Energy

For those who have not taken steps to conserve energy, their primary reasons include cost and apathy. These individuals tend to be younger, less educated, from lower income brackets and renters. They account for a very small percentage of the population.

	Total
Base: Total respondents who have not taken steps to save energy at home	(69)†
Can't afford the extra costs / don't have the money	22%
Renting / not my home	17%
Haven't really thought about it / not an issue I am concerned about	12%
Takes too much time	4%
Do not use enough / low energy use	4%
Already energy efficient house / low energy use	3%
All other mentions	13%
Don't know	7%
Decline	23%

† Data based on sample sizes of less than 100 should be interpreted with caution.

QG3: Why have you not taken steps to save energy in the home?

Commitment To Green Lifestyle

Using Conversion Model

Measuring Commitment To A Green Lifestyle

Before proceeding to the key findings of this study, we begin with an explanation of eight lifestyle segments that will be used throughout this report. To measure the extent to which residents are committed to minimizing their carbon footprint and engaging in green environmental practices, TNS' Conversion Model solution is used. The Conversion Model tool uses a psychological framework that measures the strength of the relationships between people and something else – for example: a brand, a service, a political party.

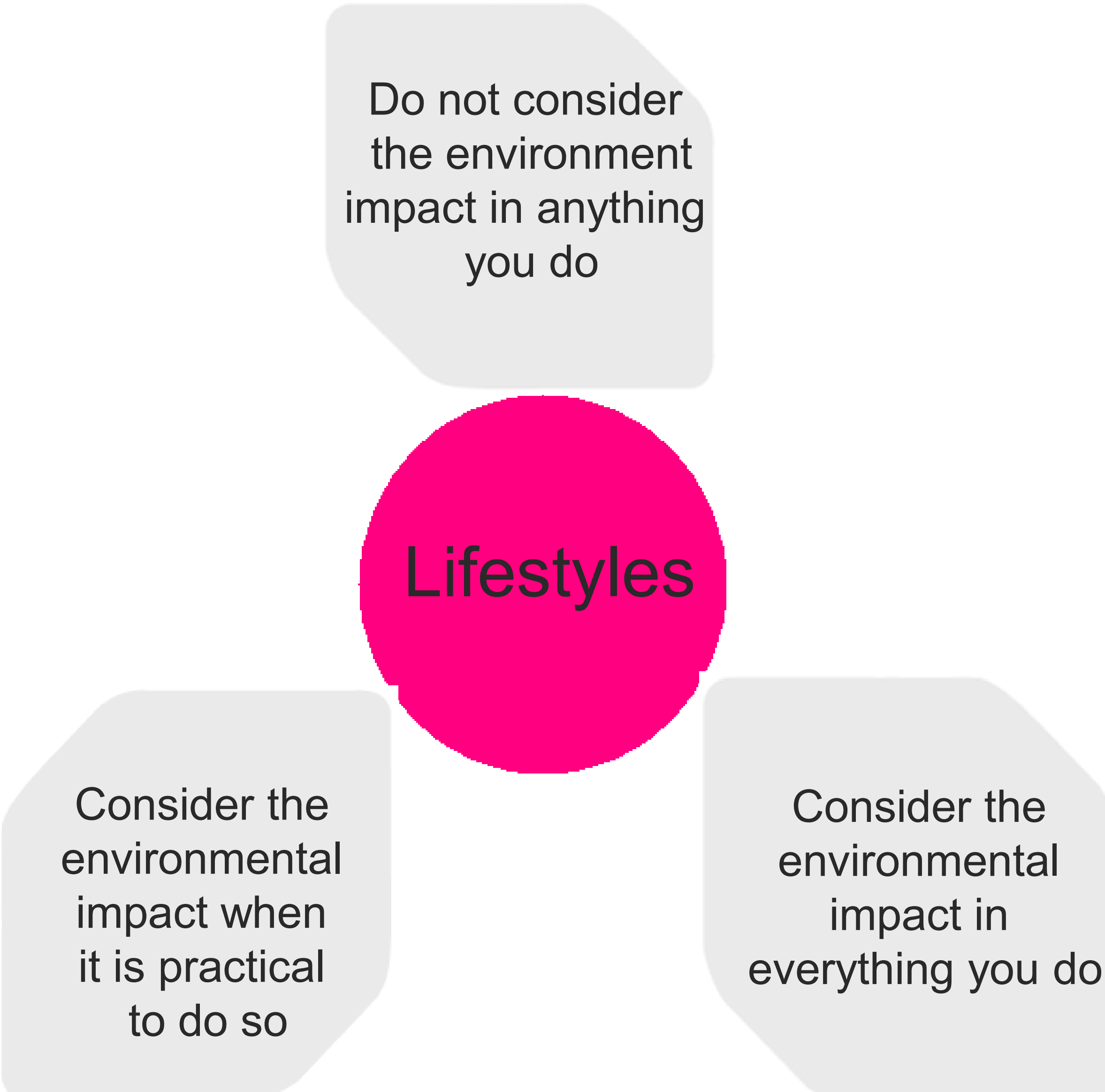
In this study we measure how committed BC residents are to living a lifestyle that considers the environmental impact of things they do and how open-minded they are to this lifestyle.

In the theory that underpins the model, there are three dimensions that contribute to a person's psychological attachment to a lifestyle…

- Needs fit: How positively people view the lifestyle they are currently in?
- Involvement in the category: How important is the lifestyle to them / does it matter?
- Ambivalence: How much are people torn between the appeal of different lifestyle choices?

The questionnaire contains a set of questions that cover these three dimensions.

Measuring Commitment To A Lifestyle



Three different lifestyles were developed at the design phase of this study to capture the extent to which residents consider the environmental impact of their actions. Some residents are extremely environmentally conscientious, some are not, and many are somewhere in between.

Residents can be closely associated with one of the three lifestyles, or they can straddle multiple lifestyles – living one, but aspiring to another.

Measuring Commitment To A Green Lifestyle

Residents are then categorized into one of eight commitment segments depending on which of the three lifestyles they relate to most. These segments will be used throughout this report.

1. Dark Greens: Extreme Environmentalists: Committed to considering the environmental impact in everything they do

2. Light greens: Not as committed to the environment as the Greens, but still caring

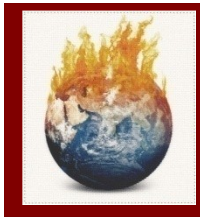
3. Potential Switchers: Consider themselves environmentally friendly, but thinking of switching to a more practical lifestyle

4. Try harders: Practical but striving to be more environmentally caring

5. Practicals: Committed to a practical environmental impact lifestyle, but still takes the environment in account

6. Extreme Practical: Committed to a pragmatic lifestyle; only considers the environmental impact only when it is reasonable or practical to do so

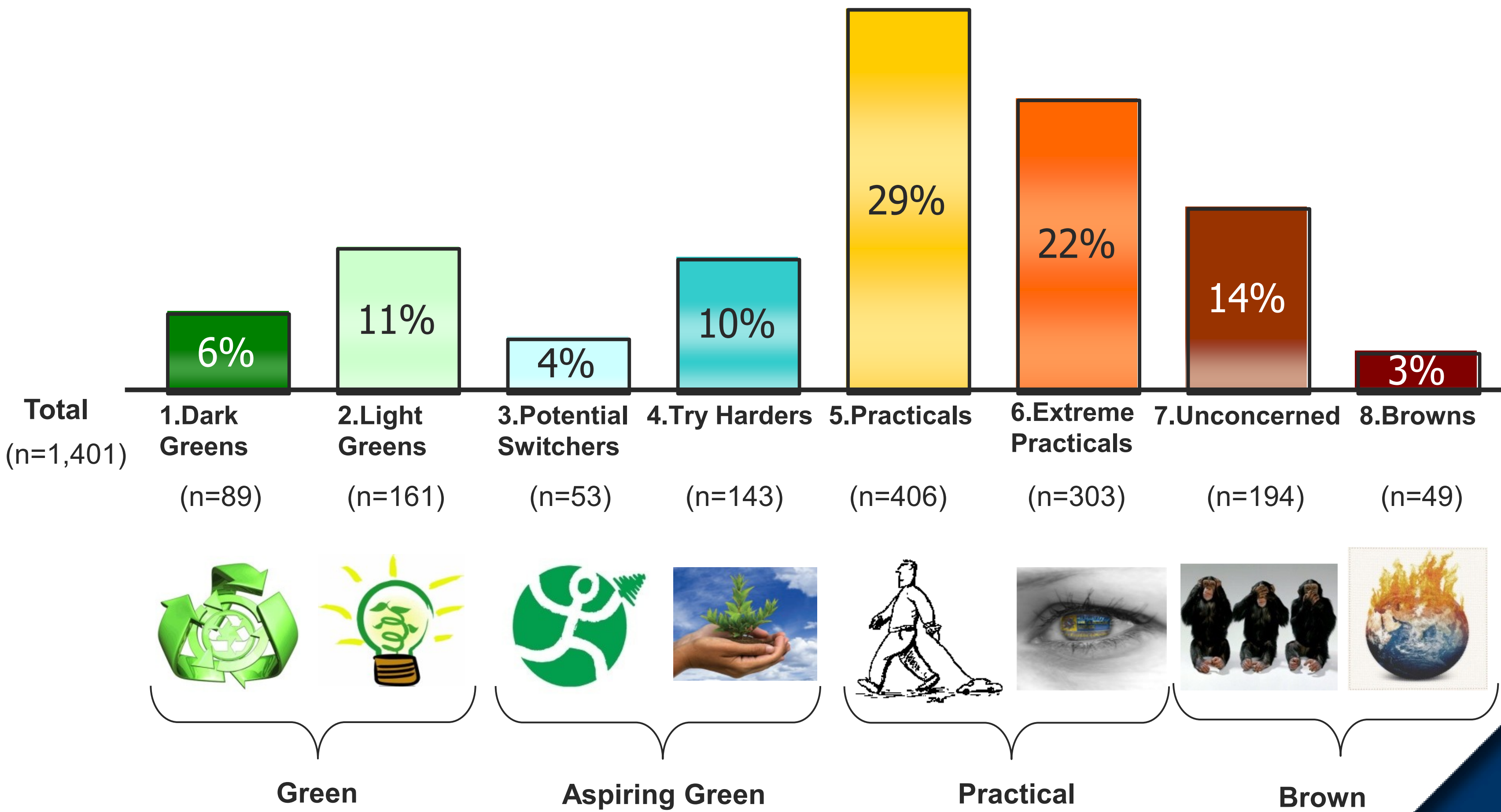
7. Unconcerned: Don’t think that much about the impact their decisions have on the environment



8. Browns: Don’t think at all about the environmental impact in anything they do

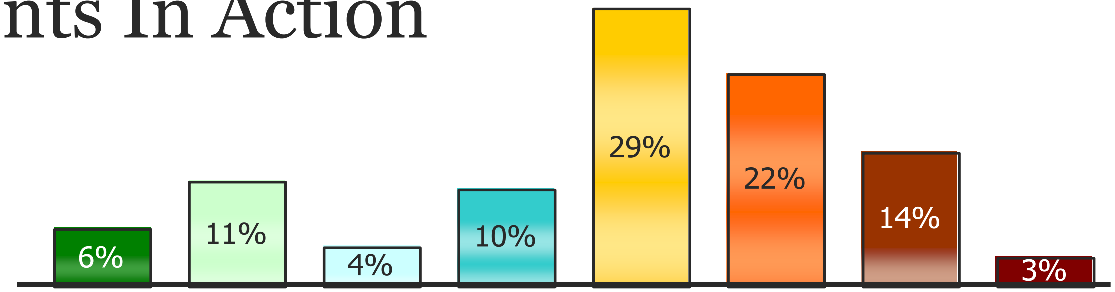
Lifestyle Segment Distribution

Just under one-fifth of BC residents are "Green" (Dark Green and Light Green combined)– they are sensitive about their environmental footprint in everything they do and buy. An equal proportion of residents are the exact opposite (Browns and Unconcerned combined)– they do not care about the environmental consequences of their actions. However, two-thirds of residents would consider more environmentally-friendly alternatives if it is practical for them to do so. In other words, if they see the value and benefits to them for choosing the greener option, they will do so.



The Lifestyle Segments In Action

Each lifestyle segment holds a different attitude towards the environment as shown by their varying levels of concern in the chart below.



The Try Harders are quite concerned about the environment (as they are striving to be more environmental)

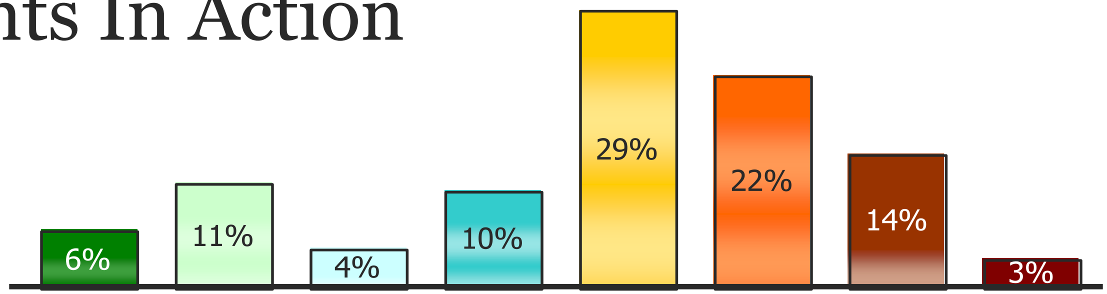
How concerned are you about…

Top-two box scores

	Total (n=1,401)	1.Dark Greens (n=89)	2.Light Greens (n=161)	3.Potential Switchers (n=53)	4.Try Harders (n=143)	5.Practicals (n=406)	6.Extreme Practicals (n=303)	7.Unconcerned (n=194)	8.Browns (n=49*)
The current state of the environment	**40%**	79%	67%	49%	49%	41%	26%	21%	16%
The future state of the environment	**45%**	80%	74%	49%	52%	46%	31%	22%	20%
The effects of climate change	**39%**	81%	65%	47%	47%	40%	22%	19%	18%
Greenhouse gas emissions	**36%**	80%	61%	49%	43%	36%	21%	17%	14%
The loss of oxygen producing forests	**46%**	85%	73%	57%	50%	45%	35%	26%	18%
The level of government or industry leadership on environmental issues	**41%**	76%	66%	49%	46%	42%	31%	21%	16%
Access to alternative energy solutions	**41%**	75%	65%	55%	46%	41%	31%	19%	14%

* Caution: small base size

The Lifestyle Segments In Action



Top-two box scores	Total (n=1,401)	1.Dark Greens (n=89)	2.Light Greens (n=161)	3.Potential Switchers (n=53)	4.Try Harders (n=143)	5.Practicals (n=406)	6.Extreme Practicals (n=303)	7.Unconcerned (n=194)	8.Browns (n=49*)
Do you think Terasen Gas should be investing in biogas projects?	**49%**	76%	65%	53%	51%	50%	46%	31%	14%
Do you think Terasen Gas should invest in offering a biogas program to its residential customers?	**47%**	75%	62%	55%	48%	48%	44%	31%	14%
All things being equal, if Terasen Gas offered a biogas program, how likely would you be to sign up?	**31%**	48%	46%	45%	35%	29%	27%	22%	8%
Knowing this information, how likely would you be to purchase a carbon offset for your personal natural gas use in order to reduce your individual environmental footprint?	**16%**	35%	32%	25%	11%	16%	11%	9%	4%

Even though the Try Harders, Practicals and the Extreme Practicals believe that Terasen Gas should be investing in a biogas project, when it comes to actually signing up or paying, they are far less enthusiastic

* Caution: small base size

Reaching Out To The Greens

The Greens are the most likely segments to enroll in a biogas program. So, naturally it begs the questions – who are they and how does one best reach them? This group tends to skew towards female and have taken steps to save energy in the past. If Terasen maintains a database of households that have signed up for previous energy savings projects, this may be one way to access this segments. Additionally, there is a large concentration of Light Greens who receive their gas bill directly from Terasen. The gas bill may be another channel for reaching this group.

	Lifestyles Segments							
	Dark Greens	Light Greens	Potential Switchers	Try Harders	Practicals	Extreme Practicals	Uncon-cern	Browns
Base Size	(89)†	(161)	(53)†	(143)	(406)	(303)	(194)	(49)††
HAVE TAKEN STEPS IN PAST TO SAVE ENERGY								
Yes	100%	97%	91%	96%	95%	91%	80%	59%
No	0%	2%	6%	1%	2%	6%	10%	31%
Don't Know	0%	1%	4%	4%	3%	3%	9%	10%
GENDER								
Male	34%	30%	38%	30%	37%	35%	38%	63%
Female	66%	70%	62%	70%	63%	65%	62%	37%
HOW RECEIVE BILL								
Receive bill directly from Terasen Gas	46%	63%	49%	58%	59%	58%	56%	51%
Pay gas bill indirectly	20%	11%	23%	13%	15%	14%	13%	12%
Does not use gas	29%	24%	26%	25%	24%	25%	24%	31%

† Data based on sample sizes of less than 100 should be interpreted with caution.

†† Data based on sample sizes of less than 50 should be interpreted with extreme caution.

Opinions On Biogas Program

Opinions On Terasen's Involvement With Biogas Projects

Approximately two-in-three residents will support Terasen if it chooses to invest in biogas projects. A similar number would support Terasen, if it offers a biogas program for customers. It should be noted that very few residents would oppose such initiatives. As-long-as residents understand the benefits of biogas, there will be strong support for Terasen to be involved with these projects.

Should Terasen Be Investing In Biogas

	Total
Base: Total respondents	(1,401)
Yes (8-10)	67%
Maybe (4-7)	27%
No (1-3)	2%
Decline	4%

Should Terasen Offer A Biogas Program

	Total
Base: Total respondents	(1,401)
Yes (8-10)	65%
Maybe (4-7)	30%
No (1-3)	1%
Decline	4%

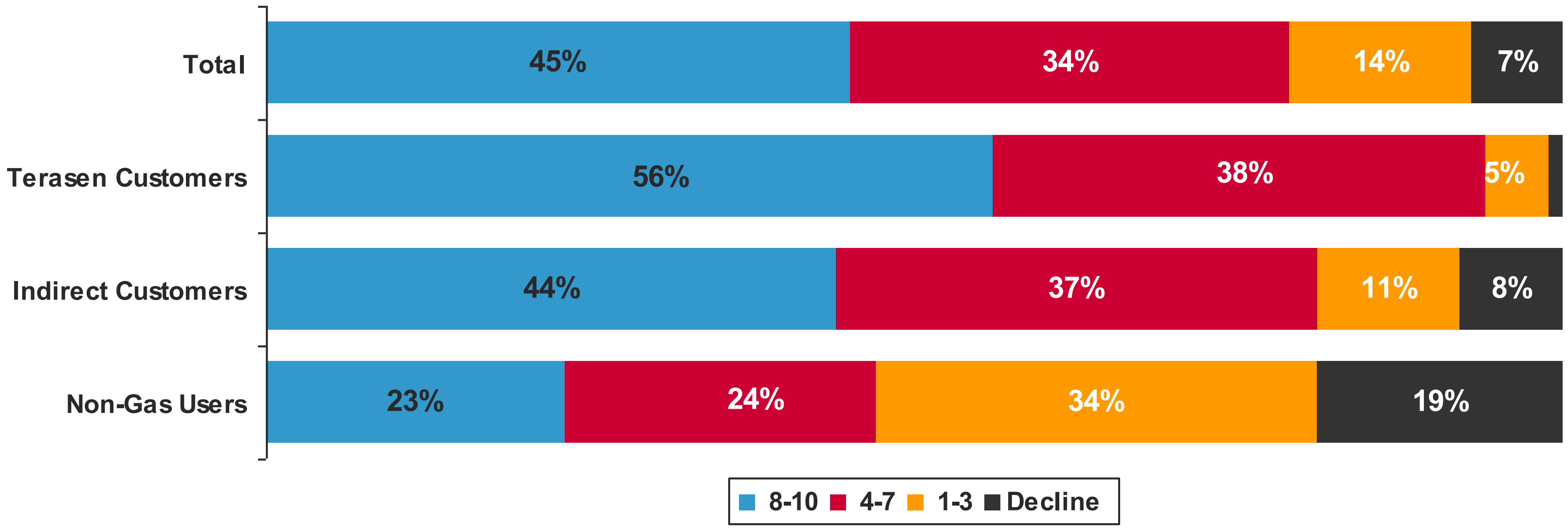
QT2: (On a scale of 1 – Definitely not to 10 – Definitely) Do you think Terasen Gas should be investing in biogas projects?

QT3: (On a scale of 1 – Definitely not to 10 – Definitely) Do you think Terasen Gas should invest in offering a biogas program to its residential customers?

Likelihood To Sign Up For Terasen Biogas Program

Although two-thirds of residents would endorse a Terasen biogas program (from the findings shown on the previous page), the actual market for biogas is smaller as not everyone who supports the program will sign up for it. Forty-five percent of residents express a strong likelihood to sign up for a Terasen biogas program. Likelihood to sign up is strongest among those Terasen customers who receive their bill directly from Terasen. At the same time, there is some interest among non-gas users too to convert over to this greener form of energy.

Likelihood To Sign Up For Terasen Biogas Program



“Terasen Customers” receive a bill direct from Terasen. “Indirect Customers” are gas users that don’t receive a bill directly from Terasen.

QT4: (On a scale of 1 –Not very likely to 10 – Very likely) All things being equal, if Terasen Gas offered a biogas program, how likely would you be to sign up?

Opinions On Terasen Biogas Program By Lifestyle Segment

Support for Terasen's involvement in a biogas program along with likelihood to sign up for such a program increases by lifestyle segment as we move from Brown to Green. There appears to be a correlation between being committed to a particular lifestyle and one's propensity to sign up for a biogas program offered by Terasen.

Percent of Segment who …	Lifestyles Segments							
	Dark Greens	Light Green	Potential Switchers	Try Harders	Practicals	Extreme Practicals	Uncon-cerned	Browns
Base Size	(89)†	(161)	(53)†	(143)	(406)	(303)	(194)	(49)††
Believe Terasen should invest In Biogas	88%	81%	68%	70%	73%	67%	42%	37%
Believe Terasen should offer Biogas program	89%	81%	66%	69%	70%	60%	43%	35%
Are likely to sign up for a Terasen Biogas Program	64%	63%	55%	51%	44%	40%	30%	14%

† Data based on sample sizes of less than 100 should be interpreted with caution.

†† Data based on sample sizes of less than 50 should be interpreted with extreme caution.

The above results are from questions asked of all respondents, and then broken out by lifestyle segment

Motivators For Enrolling In Terasen Biogas Program

Residents who express an interest in signing up for a biogas program were asked why they would sign up. Their motivations include the preservation of nature and providing for future generations and doing the "right thing".

Residents will require Terasen to demonstrate how biogas accomplishes these objectives. It is important that communications about a potential Terasen biogas program focus on these concerns.

Motivations For Signing Up (All Mentions)

	Total
Base: Total respondents that are very likely to sign up for a biogas program	(816)
Preserving nature	77%
Providing for future generations	74%
Doing the right thing	73%
Human health	63%
Supporting local farmers by providing income for their waste streams	62%
Promoting new technologies	60%
Supporting local developments	50%
Being on the cutting edge	14%
Pricing / low price / cost efficient	4%

Most Important Motivation For Signing Up

	Total
Base: Total respondents that are very likely to sign up for a biogas program	(816)
Providing for future generations	25%
Preserving nature	22%
Doing the right thing	20%
Human health	9%
Promoting new technologies	8%
Supporting local farmers by providing income for their waste stream	6%
Supporting local developments	3%
Don't know	3%

QT5: What, if any, would be your motivation for signing up for such a program? (select all that apply)
QT6: And what would be your most important motivation for signing up for such a program? (select one only)

Motivators For Enrolling In Terasen Biogas Program (cont'd)

Although more Terasen customers would sign up for a biogas program compared to non-gas users, the motivations for signing up are universal. There are hardly any differences between why a gas user would sign up for the program compared to a non-gas user.

Motivations For Signing Up

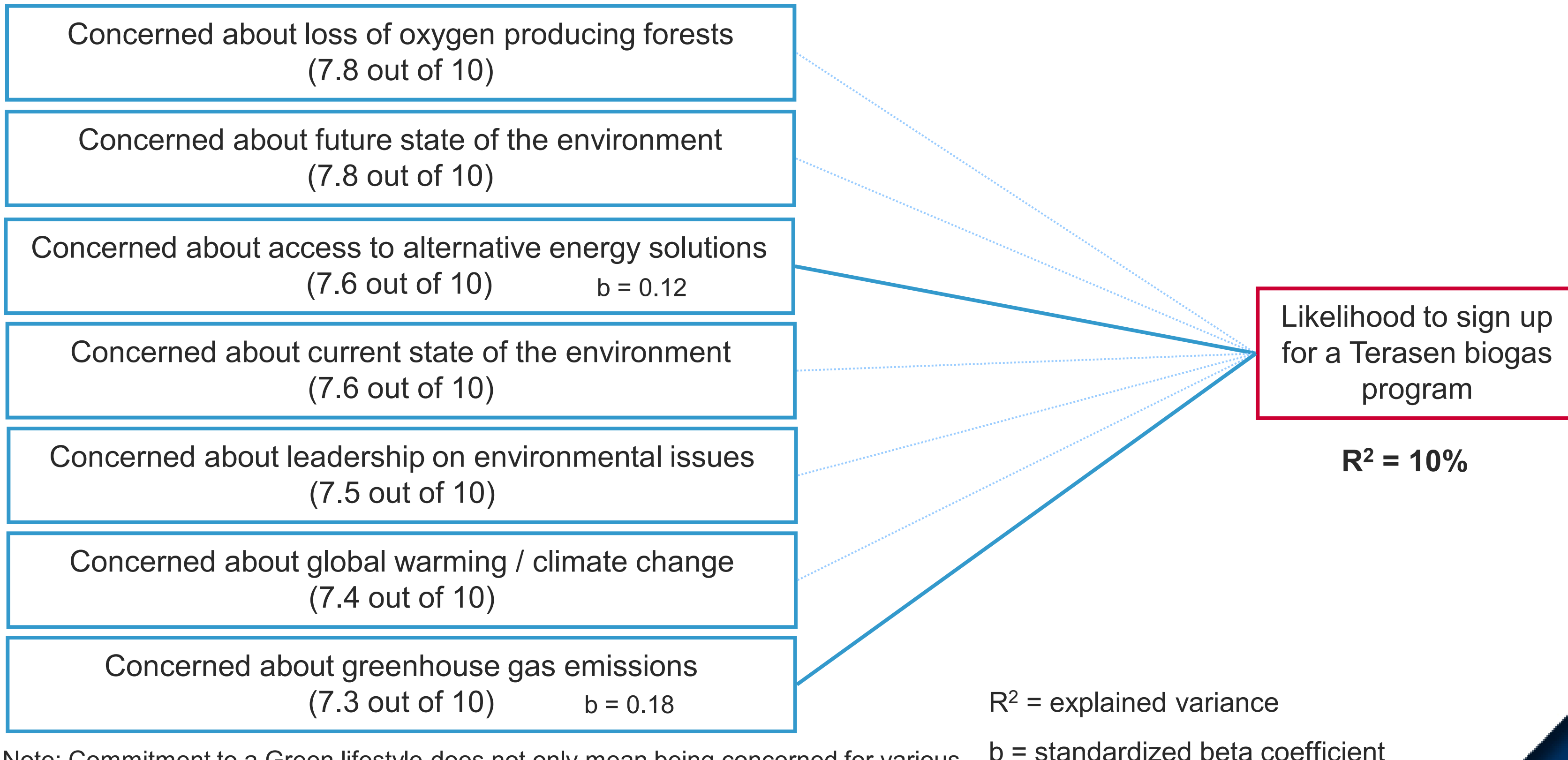
	Total	Terasen Customers	Indirect Customers	Non Gas Users
Base: Total respondents that are very likely to sign up for a biogas program	(816)	(570)	(114)	(108)
Preserving nature	77%	76%	81%	77%
Providing for future generations	74%	75%	75%	74%
Doing the right thing	73%	73%	75%	71%
Human health	63%	63%	66%	60%
Supporting local farmers by providing income for their waste streams	62%	62%	67%	62%
Promoting new technologies	60%	61%	61%	59%
Supporting local developments	50%	48%	54%	**57%**
Being on the cutting edge	14%	13%	15%	16%
Pricing / low price / cost efficient	4%	5%	1%	1%

"Terasen Customers" receive a bill direct from Terasen. "Indirect Customers" are gas users that don't receive a bill directly from Terasen.

QT5: What, if any, would be your motivation for signing up for such a program? (select all that apply)

Key Drivers For Enrolling In Terasen Biogas Program

In this study, we wanted to measure the extent that environmental concerns had on one's intentions to sign up for a biogas program. To do this, we conducted a regression analysis – a commonly used technique for identifying key drivers. Although the majority of residents express strong concerns for the environment, the regression analysis shows (that all things being equal) there is a weak correlation between environmental concerns and one's willingness to sign up for a Terasen biogas program. Concerns about greenhouse gas emissions and access to alternative fuel sources are predictors of enrolment in a Terasen biogas program. However, all other environmental concerns are non predictors.



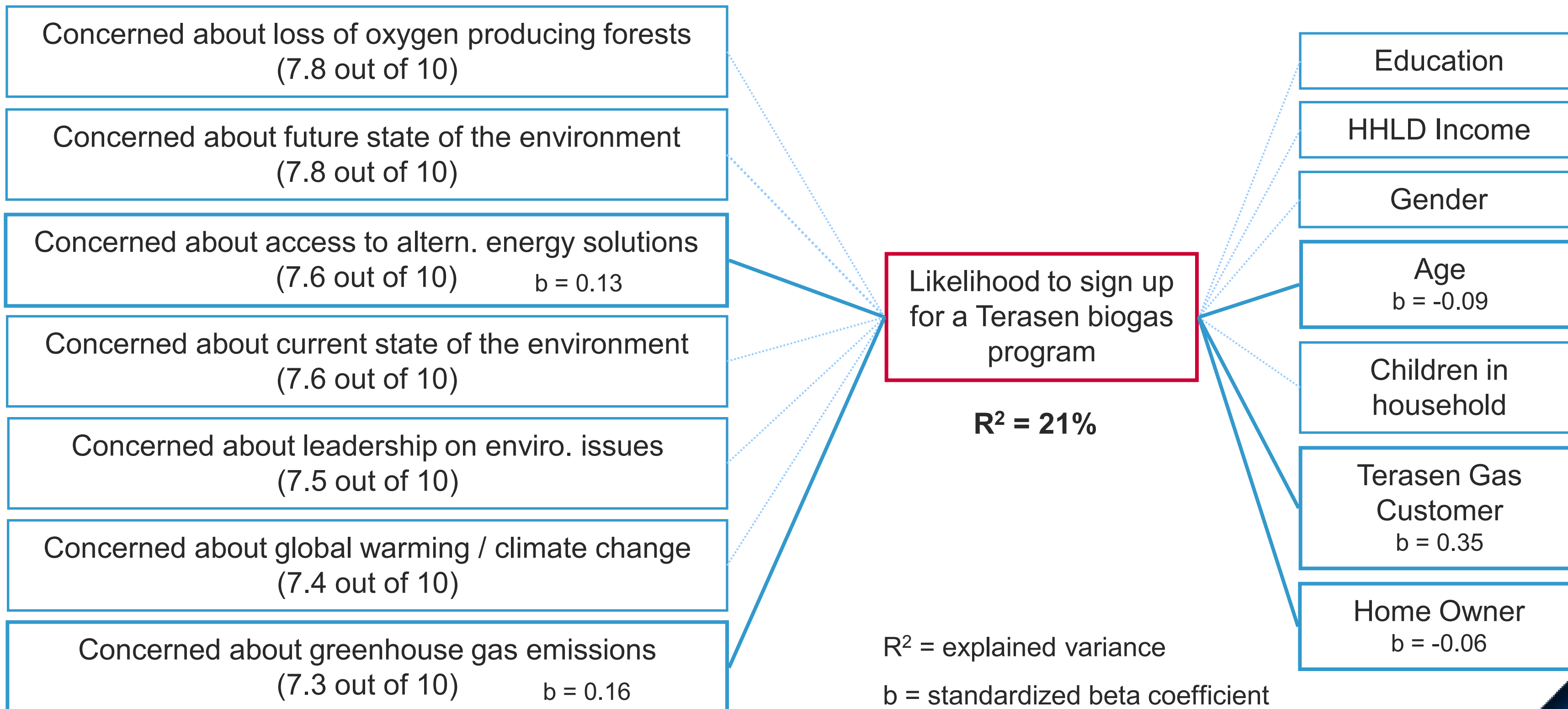
Note: Commitment to a Green lifestyle does not only mean being concerned for various environmental issues, but also involves taking actions to reduce those environmental concerns.

QM1: How concerned are you about…? (10-point scale)

QT4: All things being equal, if Terasen Gas offered a biogas program, how likely would you be to sign up? (10-point scale)

Key Drivers For Enrolling In Terasen Biogas Program

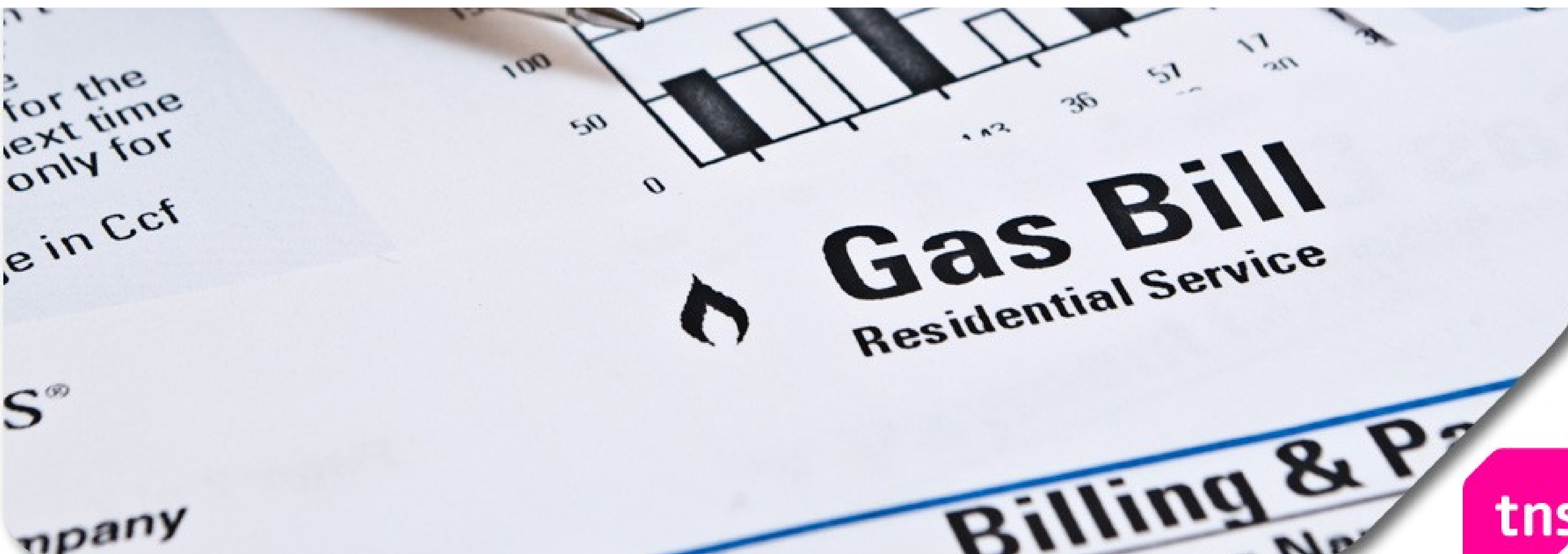
The addition of demographics to the regression model helps to explain the key drivers of enrolment in a Terasen biogas program. With demographics, we are still only able to explain 21% of the model. From our experience, strong models can typically explain over 60% of the dependent variable. The model shows that homeowners and older residents are more against signing up for the program. Whereas, Terasen Gas customers (those that receive a gas bill directly from Terasen) are more likely to sign up for such a program. Note: neither one of these two models factor in consumer hesitation with respect to increased prices that would be connected to this program – a factor that we observe is a salient issue for residents, but not one that can be incorporated into the model.



QM1: How concerned are you about…? (10-point scale)
QT4: All things being equal, if Terasen Gas offered a biogas program, how likely would you be to sign up? (10-point scale)

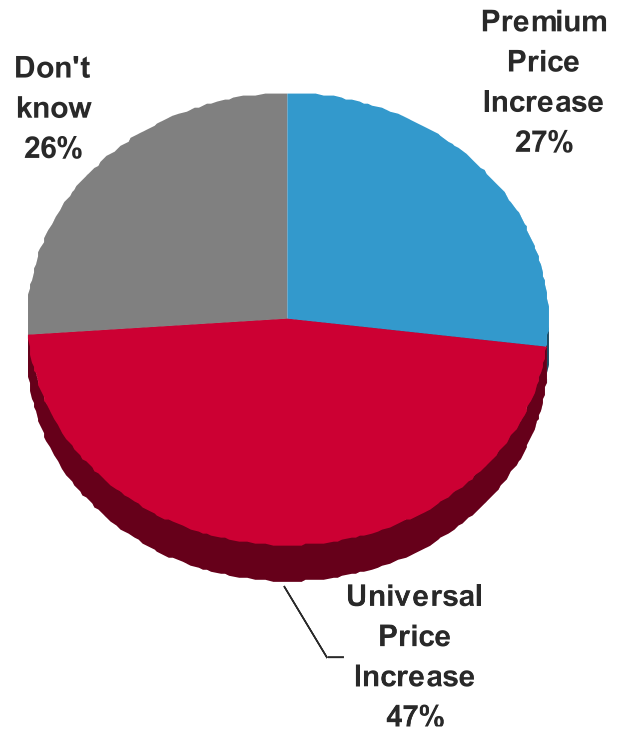
Price For Biogas

Preferred Cost Structure And Pricing Levels



Premiums Versus Universal Price Increase

Residents who expressed an interest in signing up for a biogas program were asked directly whether they would prefer to have a Terasen biogas program funded through a universal price increase (borne by all consumers) or through price premiums for only those who enroll in the program. There was a stronger preference voiced for a universal price increase (47%), compared to a biogas program people can sign up for at a premium (26%), but a considerable number of respondents indicated they did not know which one they would prefer (27%).



Base: Respondents likely to sign up for biogas program (n=860)

QP1: The costs for a biogas program can be offered to consumers in one of two ways. Which way would you prefer to see Terasen offer this program, if it were to do so? (select one only)

Acceptable Pricing Levels For Biogas Program

Since there is no clear preference for how a Terasen Gas biogas program would be funded, either one of the two options presented could be met with resistance. However, the larger issue for consumers surrounding price will be the increases they see in their gas bill. What is an acceptable price increase? To answer this question, both direct and indirect lines of questioning were used to understand the optimal price points for BC residents.

First, using a direct method, residents were asked whether or not they would support a Terasen biogas program if all customers had to pay an X% increase in the current commodity price of natural gas. Four different price increases were explored:

- 3% more ($1.80 per month extra);
- 2% to 3% more ($1.20 to $1.80 per month extra);
- 1% to 2% more ($0.60 to $1.20 per month extra); and,
- 0.5% to 1% more ($0.30 to $0.60 per month extra).

Respondents were randomly assigned to one of three groups. The first group was asked if they would support a biogas program if all customers had to pay 3% more than the current commodity price of natural gas. If they said no, they were then asked whether they would support the program if the price was 2% more. The second group of respondents were queried on a 2% and 1% price increase, while the third group was asked about a 1% and 0.5% increase.

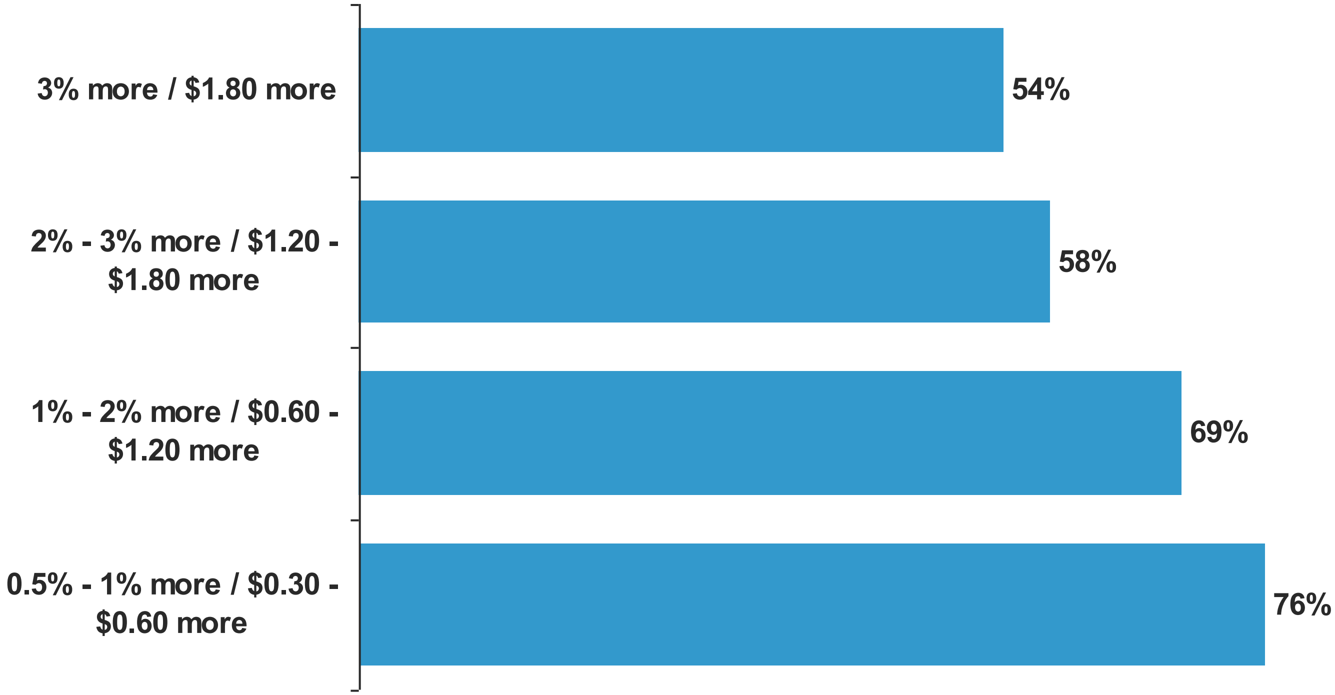
To calculate the support within a 2% to 3% increase in price, the average scores were taken for the first two respondent groups (with each group receiving equal weighting). To calculate the support within a 1% to 2% increase in price, the average scores were taken for the latter two groups (with each group receiving equal weighting).

For an indirect measure for acceptable pricing levels, a Discrete Choice Model analysis is conducted. This analysis is found in a later section of this report.

QP1: The costs for a biogas program can be offered to consumers in one of two ways. Which way would you prefer to see Terasen offer this program, if it were to do so? (select one only)

Acceptable Pricing Levels For Biogas Program

As expected, support for the program decreases as the potential price of gas increases. It is interesting to note that nearly one-quarter of residents find a negligible increase of 0.5% unacceptable. Right away, one-quarter of the market would resist the introduction of a biogas program on price alone. The sharpest decline in support occurs when the price point is raised beyond a 2% increase. Nevertheless, even at a 3% price increase, there is a high level of support (over 50% of all residents would still support the program).

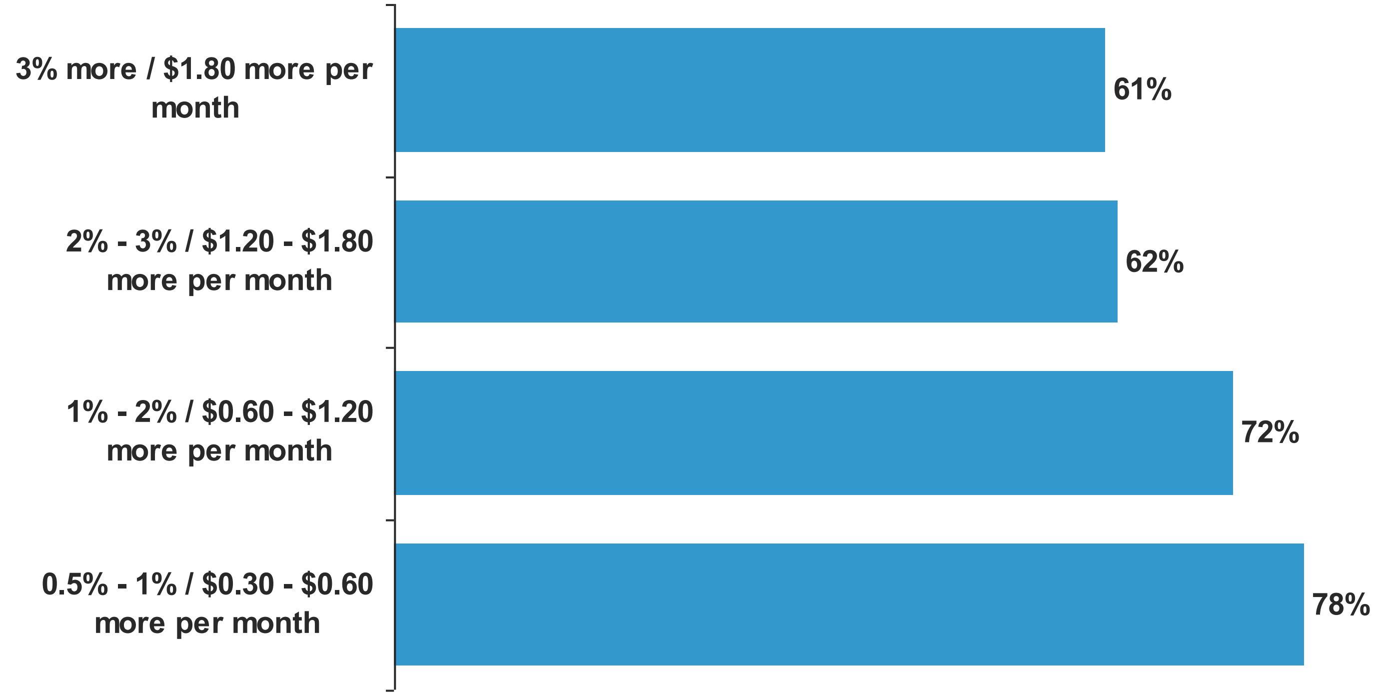


Percent of residents who would support program at specified price point

QP1A: If the cost of biogas is borne by all customers and you had to pay 3% more than the current commodity price of natural gas-which is about $1.80 more than the current monthly charge-, would you or would you not support such a biogas program?
QP1B / QP2A: If the cost of biogas is borne by all customers and you had to pay 2% more than the current commodity price of natural gas-which is about $1.20 more than the current monthly charge-would you or would you not support such a biogas program?
QP2B / QP3A: … pay 1% more than the current commodity price of natural gas-which is about $0.60…?
QP3B: …pay 0.5% more than the current commodity price of natural gas-which is about $0.30…?

Acceptable Pricing Levels For Biogas Program - Customers

Similar to the sentiment expressed by the BC resident population, support for the biogas program decreases among Terasen residential customers as the potential impact on their gas bill increases. Seventy-eight percent of residential customers indicated they would support a universal price increase of 0.5% to 1%. However, slightly fewer (62%) would still support a universal price increase of up to 3%, revealing there is a substantial proportion of the market willing to financially support biogas initiatives.



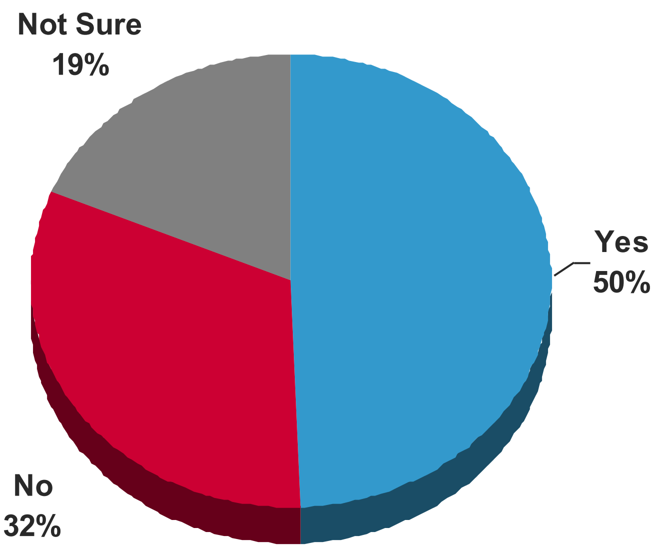
Percent of Terasen Residential Customers who would support program at specified price point

QP1A: If the cost of biogas is borne by all customers and you had to pay 3% more than the current commodity price of natural gas-which is about $1.80 more than the current monthly charge-, would you or would you not support such a biogas program?
QP1B / QP2A: If the cost of biogas is borne by all customers and you had to pay 2% more than the current commodity price of natural gas-which is about $1.20 more than the current monthly charge-would you or would you not support such a biogas program?
QP2B / QP3A: … pay 1% more than the current commodity price of natural gas-which is about $0.60…?
QP3B: …pay 0.5% more than the current commodity price of natural gas-which is about $0.30…?

Opinions On Carbon Offsets

Carbon Offsets: Awareness

Approximately half of BC residents have heard of the term “carbon offset”. The market segments that are most likely to have heard of carbon offsets are also the ones that are more likely to sign up for a biogas program (i.e., highly educated, high income, home owners). However, if Terasen is to offer carbon offsets in the future, it will need to first raise public awareness of this product.



Base: Total respondents (n=1,401)

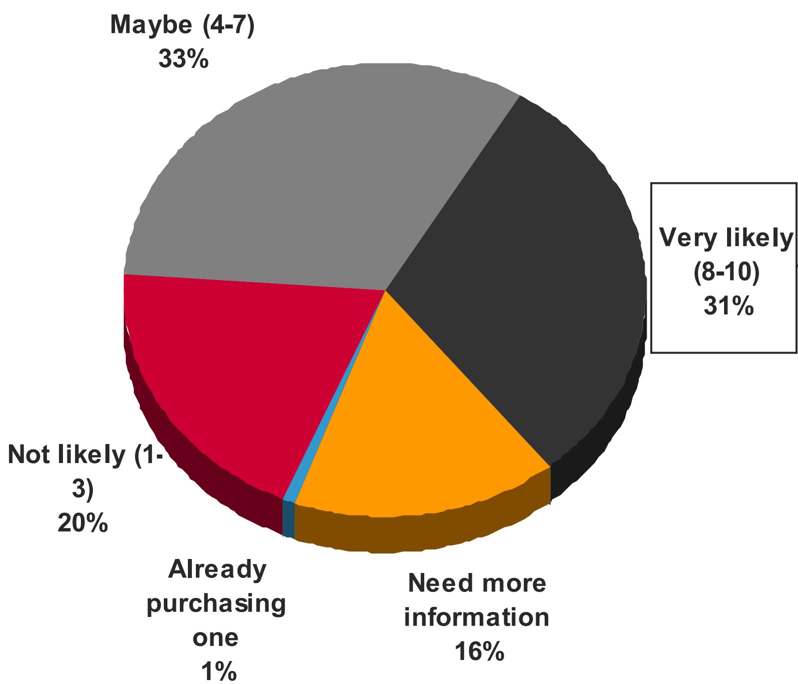
Percent Who Have Heard Of “Carbon Offsets”	
Education: University / Post Graduate	65%
Gender: Male	62%
Household Income: $60K+	58%
Region: Vancouver Island	58%
Home Owner	52%

QC1: Have you heard of the term ‘carbon offset’?

Carbon Offsets: Purchase Intentions

Only one percent of residents have purchased a carbon offset in the past. After being provided with a full definition of a carbon offset, less than one-third of residents say they would strongly consider purchasing a carbon offset (if they have not already). And among those who would purchase one, 50% would purchase from their local utility provider. A large proportion would want more information before they decide whom they would purchase from.

Likelihood Of Purchasing Carbon Offsets



Base: Total respondents (n=1,401)

Preferred Source

	Total
Base: Total respondents who are very likely to purchase a carbon offset in order to reduce their environmental footprint	(428)
Your local utility provider	50%
A 3rd-party provider that supports projects in BC	21%
A 3rd-party provider that supports projects outside BC	1%
Need more information / Don't know	37%

QC2: (On a scale of 1 –Not at all likely to 10 – Extremely likely) Knowing this information, how likely would you be to purchase a carbon offset for your personal natural gas use in order to reduce your individual environmental footprint? (select one only)
QC3: Carbon offsets are sold through a number of sources. Would you prefer to purchase an offset through… (select all that apply)

tns

Carbon Offsets: Preferred Project Investments

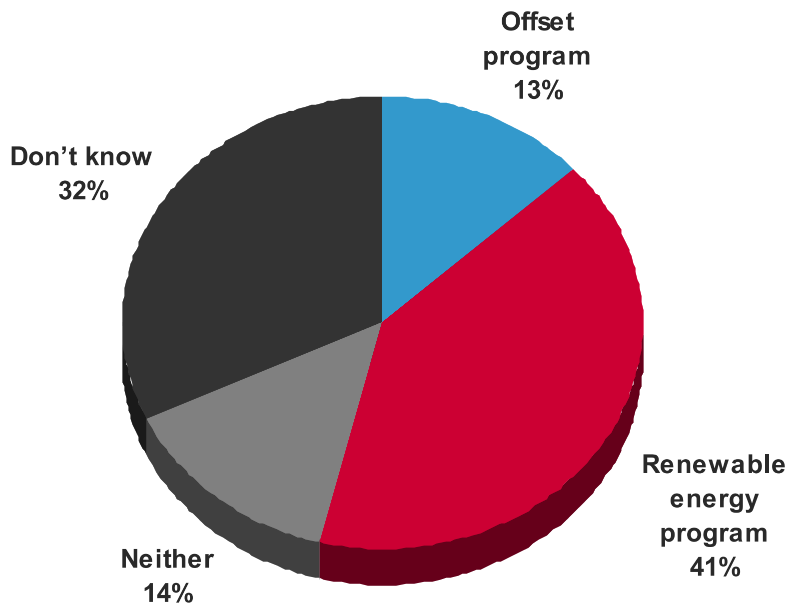
Solar and wind power projects, along with forestation projects garnered the greatest consideration among both the larger population and among those residents who are likely to buy carbon offsets. These are the higher-priority projects that residents would like Terasen to invest in – if it were to offer carbon offsets.

	Total	Likely To Purchase Carbon Offsets
Base Size	(1,401)	(428)
Solar power - generate energy from sunlight	70%	81%
Wind power - use wind to create electricity	69%	79%
Forestation - plant trees which absorb carbon dioxide	60%	74%
Environmental buildings - make buildings more energy efficient	53%	64%
Geothermal power - energy extracted from the ground for heating	53%	59%
Fuel efficiency - burn a particular fuel more efficiently	50%	61%
Efficient lighting- replace light bulbs with fluorescent lamps	44%	56%
Fuel substitution - switch to a fuel that emits less carbon such as diesel trucks to natural gas trucks	43%	58%
Public transportation - subsidize or encourage the use of public transport	40%	50%
Heat-electricity cogeneration - create electricity and heat together	33%	41%
3rd-party biogas projects - within BC	32%	44%
Energy from biomass - burn wood waste to generate electricity	28%	36%
3rd-party biogas projects - outside BC	9%	12%
No preference	14%	5%

QC5: What types of offset projects would you want to see Terasen Gas invest in outside of its own renewable energy projects? (select all that apply)

Carbon Offset Versus Renewable Energy Programs

The earlier results on likelihood to sign-up in a biogas program (45%) and the likelihood to purchase a carbon offset (31%) would suggest that there would be a higher take-up rate among residents for a biogas program. This is confirmed, when residents are asked to choose which of the two programs they would prefer to see Terasen introduce. A renewable energy program is preferred over a carbon offset program by three-to-one.



Base: Total respondents (n=1,401)

QC4: Which of these two programs would you be more inclined to see Terasen Gas introduce, if it were to do so? (select one only)

Opinions About Carbon Offsets By Lifestyle Segment

The greener lifestyle segments are most likely to purchase a carbon offset. Although every segment would prefer that Terasen offer residents a renewable energy program instead of a carbon offset program, it is interesting to note that Dark Greens are more likely than other lifestyle segments to see carbon offsets offered.

Percent of Segment Who …	Lifestyles Segments							
	Dark Greens	Light Green	Potential Switchers	Try Harders	Practicals	Extreme Practicals	Uncon-cerned	Browns
Base Size	(89)†	(161)	(53)†	(143)	(406)	(303)	(194)	(49)††
Are aware of carbon offsets	60%	60%	42%	55%	53%	52%	28%	37%
Are likely to purchase carbon offsets	46%	48%	43%	28%	35%	22%	18%	10%
OFFSETS VS, RENEWABLE ENERGY								
Prefer Terasen offer carbon offsets	23%	14%	11%	12%	11%	15%	11%	10%
Prefer Terasen offer renewable energy program	43%	47%	49%	48%	45%	37%	31%	31%
Prefer Terasen offer neither	7%	9%	6%	8%	12%	21%	18%	37%
Don’t know	28%	30%	34%	32%	32%	28%	40%	22%

† Data based on sample sizes of less than 100 should be interpreted with caution.

†† Data based on sample sizes of less than 50 should be interpreted with extreme caution.

Opinions About Carbon Offsets By User Type

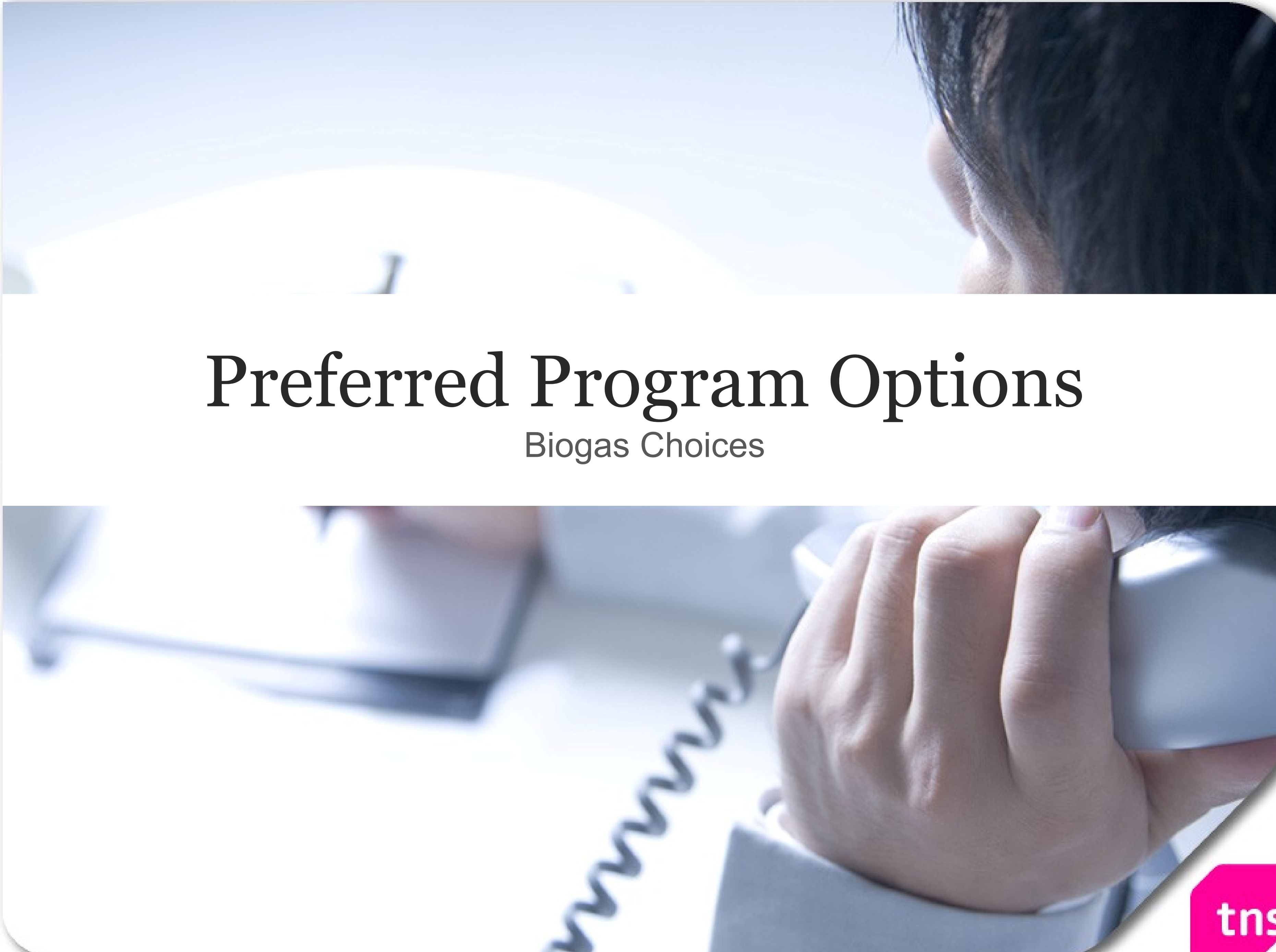
Similar to findings for a biogas program, non-gas users are less likely than gas users to purchase carbon offsets. At the same time though, over one-in-five non-gas users would strongly consider purchasing offsets. The most popular projects that non-users would like to invest in are solar and wind power technologies.

	Total	Terasen Customers	Indirect Customers	Non Gas Users
Base Size	(1401)	(799)	(200)	(352)
Are aware of carbon offsets	50%	50%	48%	52%
Are likely to purchase carbon offsets	31%	**35%**	**31%**	22%
PREFERRED PROJECT INVESTMENTS				
Solar power - generate energy from sunlight	70%	72%	71%	65%
Wind power - use wind to create electricity	69%	71%	72%	65%
Forestation - plant trees which absorb carbon dioxide	60%	61%	63%	56%
Environmental buildings - make buildings more energy efficient	53%	53%	59%	52%
Geothermal power - energy extracted from the ground for heating	53%	**57%**	**53%**	44%
Fuel efficiency - burn a particular fuel more efficiently	50%	**53%**	**54%**	44%
Efficient lighting- replace light bulbs with fluorescent lamps	44%	46%	45%	42%
Fuel substitution - switch to a fuel that emits less carbon such as diesel trucks to natural gas trucks	43%	43%	47%	40%

"Terasen Customers" receive a bill direct from Terasen. "Indirect Customers" are gas users that don't receive a bill directly from Terasen.

Preferred Program Options

Biogas Choices



Explaining Discrete Choice Analysis

When residents are asked the importance of various energy initiative program features, there is a strong chance that many of the proposed features will be said to be important – if a feature is important enough for Terasen to include in a survey, it is very likely that residents will also find it to be important to them. If everything is reported to be important, it becomes difficult to understand what actions should be taken. Therefore, researchers often use indirect ways to measure importance.

A Discrete Choice Model (DCM) is used in this study. For this model, respondents are asked to choose between a series of program alternatives that trade-off on different features. From their choices, we are able to indirectly measure which elements weighed more heavily on their selections.

A simulation model is built based on a trade-off analysis of different choice sets. This model takes into consideration various elements associated with an energy initiative program.

The model includes three dimensions. Thirty-six possible pairings of choice sets were built into the questionnaire, based on different permutations of the three dimensions. Each respondent was presented with a random set of 16 pairings and asked to select the scenario they preferred in each pairing.

The dimensions and the items presented in the model are summarized on the following page.

Levels Of Discrete Choice Model

The Three Levels and The Choice Elements

Energy Initiative
- Renewable Energy Program
- Carbon Offset Program

Percent Reduction In Green House Gas Emissions
- 10%
- 20%
- 30%
- 50%
- 80%
- 100%

Effect On Monthly Gas Bill
- The current commodity price + 10% (about extra $6/month)
- The current commodity price + 20% (about extra $12/month)
- The current commodity price + 30% (about extra $18/month)

Analysis And Output From DCM

Two outputs are produced from the DCM analysis – utility values and a ‘share of preference’ simulator.

Utility values indicate numerically how valuable each level is relative to the others. “Utility” is the net benefit that a person gets from choosing an alternative or feature. These values have no units and are interpreted in a relative manner. The utility value also shows which items within a level have a greater impact on choice, as denoted by higher values.

Second, the DCM outputs a simulator of ‘share of preference’ for all program choices. It enables the user to experiment with different scenarios and see how changing various elements can affect share of preference.

Please bear in mind that the Discrete Choice Analysis is conducted only with residents who say that Terasen should be investing in biogas projects at some level. Those who do not believe Terasen should invest in such projects are excluded from this analysis because none of the choice sets that we present would be chosen by this group.

This simulator is contained within a Microsoft Excel spreadsheet file to be provided separately.

Summary Of Utility Values

The discrete choice analysis is able to identify drivers that could not be determined by the linear regression models discussed earlier in this report. The utility values in the chart below show that Green House Gas (GHG) emissions have approximately the same importance to residents as price. These two factors are both relatively more important than the type of energy initiative that is introduced.

In reviewing all the discrete choice results holistically, it is observed that residents are captivated by the idea of reducing their own GHG emissions, but not necessarily at all costs. A GHG reduction of 30% or more would be considered a substantial reduction in one's carbon footprint.

However, the price implications are strong detractors that direct many residents to choose the least costly option. Residents are not expecting a proportionate reduction in GHG levels for the same increase in price, as we will see in the DCM simulations to follow.

The specific energy initiative used to achieve these GHG reductions is less important for residents. With that said, there is an overall preference for a renewable energy program instead of a carbon offset program. This reinforces results found in earlier parts of this report.

Summary of DCM Attribute Importance

Utility Values	Total
Energy Initiative	7.9
Percent Reduction In Green House Gas Emissions	18.5
Effect On Monthly Gas Bill	14.4

Utility Value Details

Energy Initiative (Utility Values)

Utility Values	Total
Renewable Energy Program	17.9
Carbon Offset Program	10.0

Effect On Monthly Gas Bill (Utility Values)

Utility Values	Total
Current Price + 10%	24.4
Current Price + 20%	18.3
Current Price + 30%	10.0

Reduction In Green House Gas Emissions (Utility Values)

Utility Values	Total
10%	10.0
20%	10.7
30%	16.4
50%	23.6
80%	25.1
100%	28.5

tns™

DCM Simulation #1

The following results are from the DCM simulator. Renewable energy program choices are presented, since this type of program is preferred over a carbon offset program.

To understand the tradeoff between price and GHG reductions, we create the following scenario where price increases are set in direct proportion to GHG reductions. This simulation shows that price is a strong factor as it has residents gravitating towards the lowest price options. The other reason that residents are leaning more towards Option #1 is because the GHG reduction levels selected are not high enough to offset the higher price increases.

<u>Choice #1</u>

Renewable energy program

10% price increase

10% GHG reductions

<u>Choice #2</u>

Renewable energy program

20% price increase

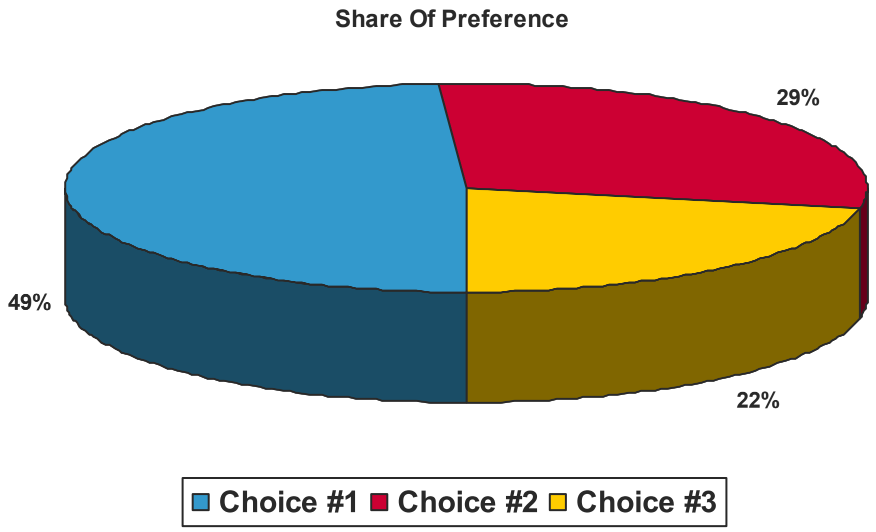
20% GHG reductions

<u>Choice #3</u>

Renewable energy program

30% price increase

30% GHG reductions



DCM Simulation #2

Using the most preferred option in the last scenario as the base, we can increase GHG reduction levels to the other two choices to understand what would be a comparable trade-off between price and GHG reductions for residents. From this exercise, Terasen would need to deliver the following GHG reductions on its renewable energy program at each of the three price points to create comparable options:

- 10% gas bill increase -> 10% reduction in GHG emissions
- 20% gas bill increase -> 30% reduction in GHG emissions
- 30% gas bill increase -> 60% reduction in GHG emissions

<u>Choice #1</u>

Renewable energy program

10% price increase

10% GHG reductions

<u>Choice #2</u>

Renewable energy program

20% price increase

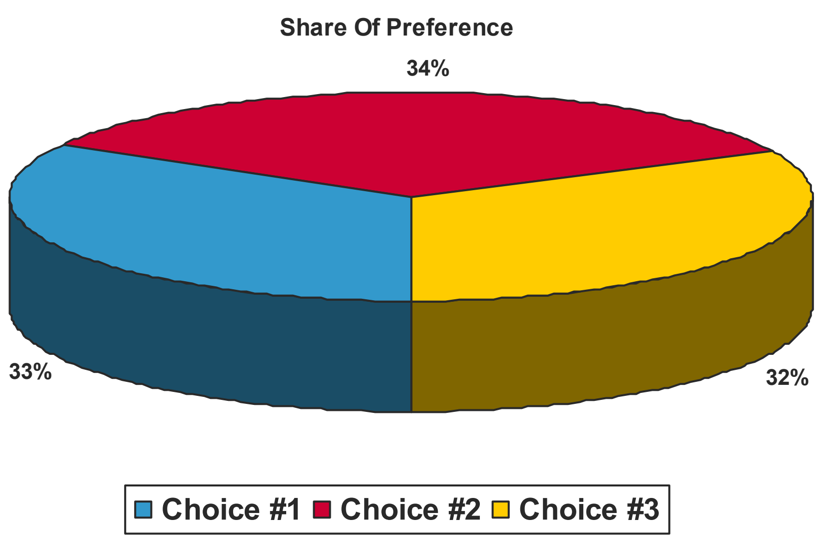
30% GHG reductions

<u>Choice #3</u>

Renewable energy program

30% price increase

60% GHG reductions



Estimating Potential Market Share

For Biogas Program

Reported Likelihood To Sign Up For Program

From the findings presented in this report, this next section of the report endeavors to estimate the potential market share for a biogas program. The projected market estimates are calculated based solely on what respondents tell us. Knowing this, we would caution that these figures should be considered best case estimates. The reason for caution is two-fold:

- People don't always do what they say – we often fall short of our intended goals; and,
- Respondents sometimes have the tendency to provide answers in a manner consistent with how they perceive we want them to answer – in this case, to sign up for a biogas program because it has positive impacts on our environment.

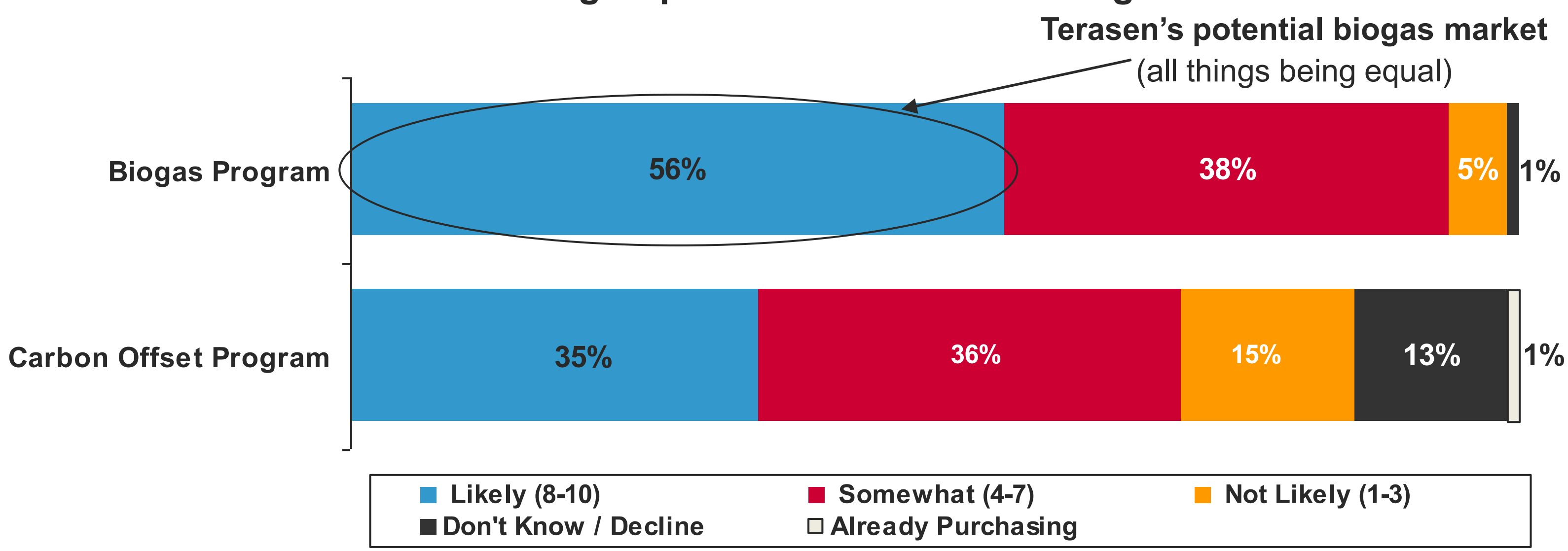
The market projections in this section of the report are based on Terasen customers who receive a gas bill directly from Terasen. We excluded all other residents from this analysis, because these customers have access to Terasen and the greatest control over whether or not their households would sign up for such program with the organization.

The reader is also urged to bear in mind that the sampling unit for this study is the household. All projections are made on the basis of residential Terasen customer households, and not individuals.

Reported Likelihood To Sign Up For Program

Since a greater number of Terasen Gas customers would sign up for a biogas program (56%) than a carbon offset program (35%), it is inferred that the potential market for a biogas program will be greater. Because it is the more appealing option, market projections will be provided for a biogas program in this section of the report. In total, 56% of residents could potentially sign up for a biogas program. Please bear in mind that this figure is only realized if prices and everything else remains the same.

Likelihood To Sign Up For Terasen Offered Programs:



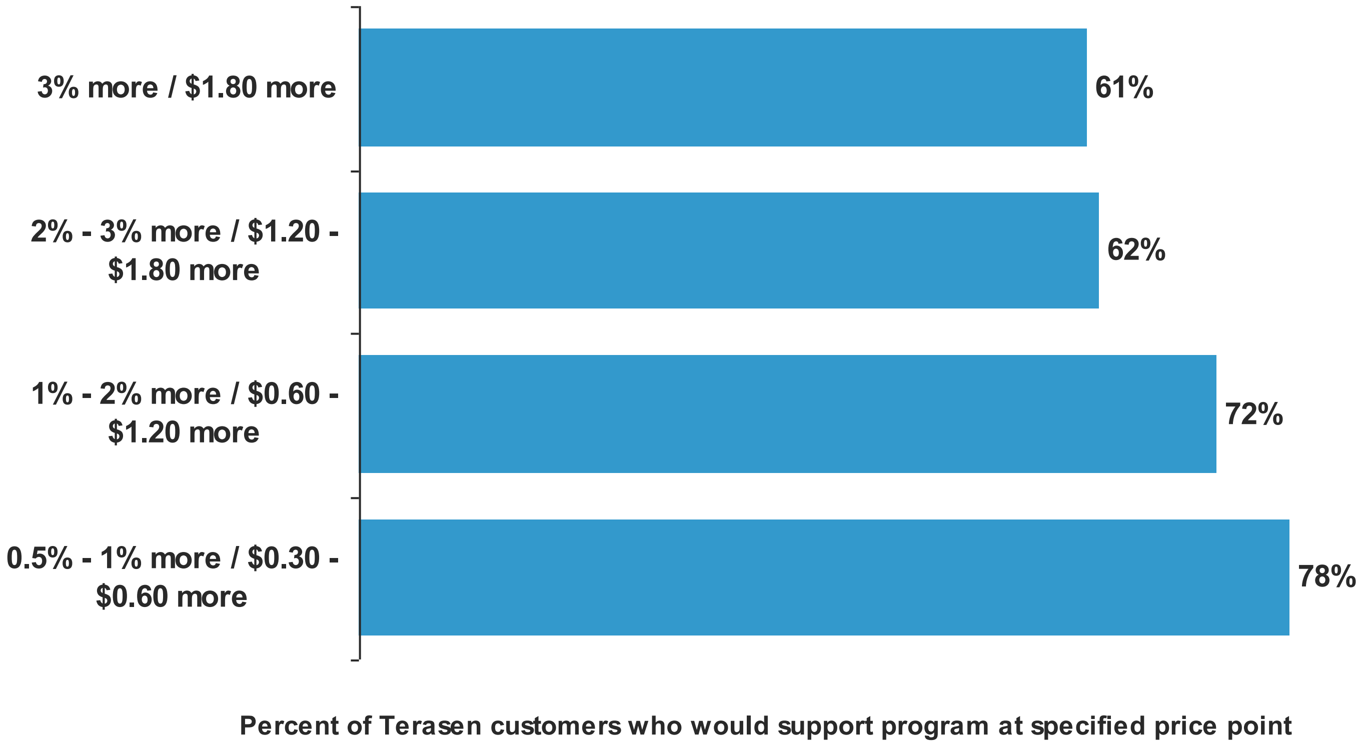
Base: Total Terasen customers (n=799)

QT4: (On a scale of 1 –Not very likely to 10 – Very likely) All things being equal, if Terasen Gas offered a biogas program, how likely would you be to sign up?

QC2: (On a scale of 1 –Not at all likely to 10 – Extremely likely) Knowing this information, how likely would you be to purchase a carbon offset for your personal natural gas use in order to reduce your individual environmental footprint? (select one only)

Terasen Customers' Reactions To Price Increases

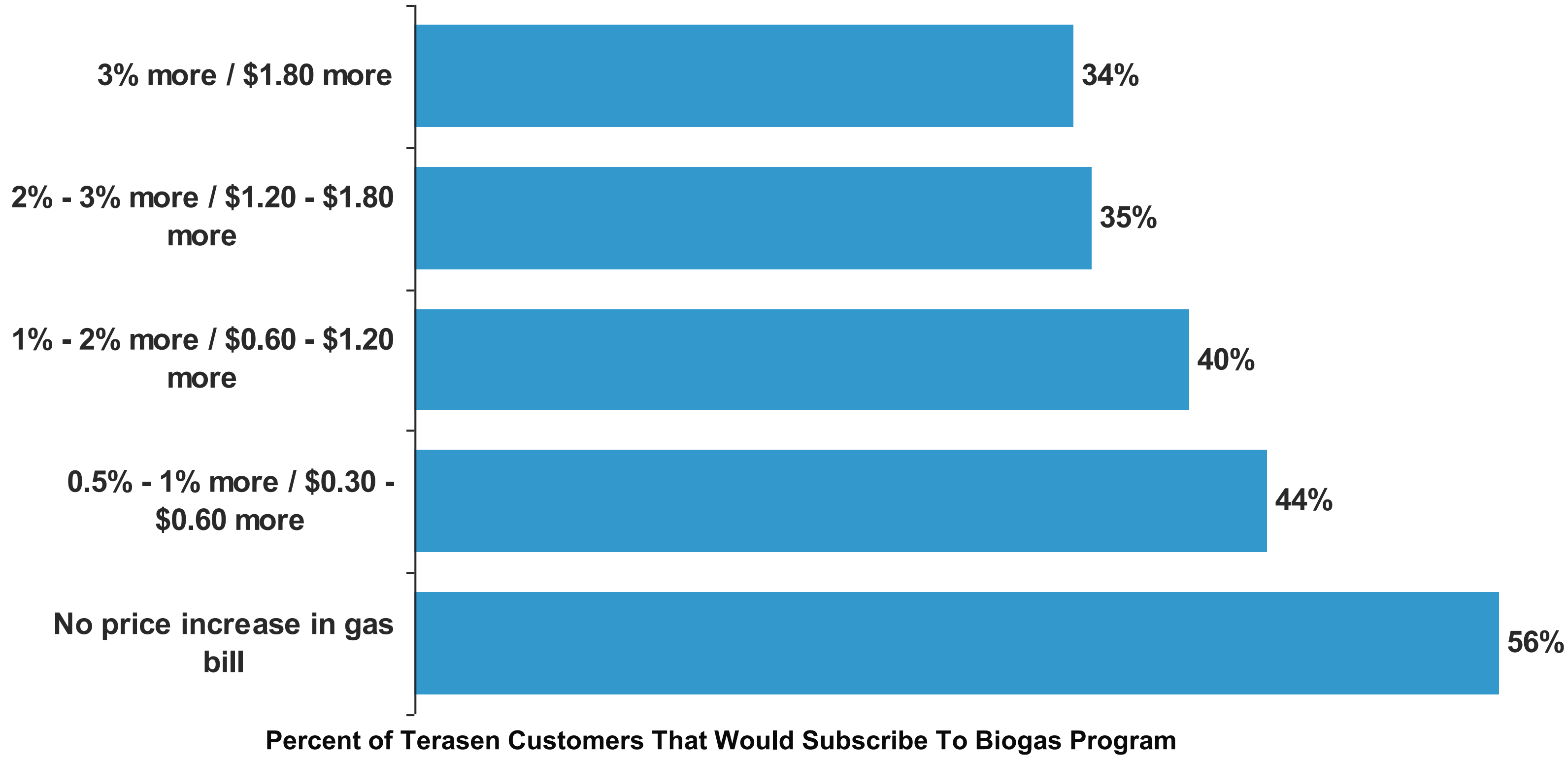
As discussed earlier in this report, support for a biogas program decreases, as residents' gas bills increase. This support was tested at price increases borne by all customers from 0.5% to 3%. In the chart below, we calculate the support level among Terasen Gas customers at these price ranges.



QP1A: If the cost of biogas is borne by all customers and you had to pay 3% more than the current commodity price of natural gas-which is about $1.80 more than the current monthly charge-would you or would you not support such a biogas program?
QP1B / QP2A: If the cost of biogas is borne by all customers and you had to pay 2% more than the current commodity price of natural gas-which is about $1.20 more than the current monthly charge-would you or would you not support such a biogas program?
QP2B / QP3A: … pay 1% more than the current commodity price of natural gas-which is about $0.60…?
QP3B: …pay 0.5% more than the current commodity price of natural gas-which is about $0.30…?

Market Size At Different Price Points (Maximum Potential)

Next we calculate potential market share figures by multiplying the proportion of Terasen residential customers who would sign up for this program (56%) by proportion of customers willing to support a biogas program at each price point.



QP1A: If the cost of biogas is borne by all customers and you had to pay 3% more than the current commodity price of natural gas-which is about $1.80 more than the current monthly charge-would you or would you not support such a biogas program?
QP1B / QP2A: If the cost of biogas is borne by all customers and you had to pay 2% more than the current commodity price of natural gas-which is about $1.20 more than the current monthly charge-would you or would you not support such a biogas program?
QP2B / QP3A: … pay 1% more than the current commodity price of natural gas-which is about $0.60…?
QP3B: …pay 0.5% more than the current commodity price of natural gas-which is about $0.30…?

Testing Higher Price Points

In the previous slides, we tested price increases of up to 3%, with the price of a biogas program being borne by all BC consumers. In this study, we also tested support for the program at higher price levels (ranging for gas bill increases of 10% to 30%) within the discrete choice model. To look at how Terasen customers would react to different price ranges, we set up a scenario with three realistic choices. At 10%, 20% and 30% price increases, we combined each price point with a proportionate GHG reduction level.

<u>Choice #1</u>

Renewable energy program

10% price increase

10% GHG reductions

<u>Choice #2</u>

Renewable energy program

20% price increase

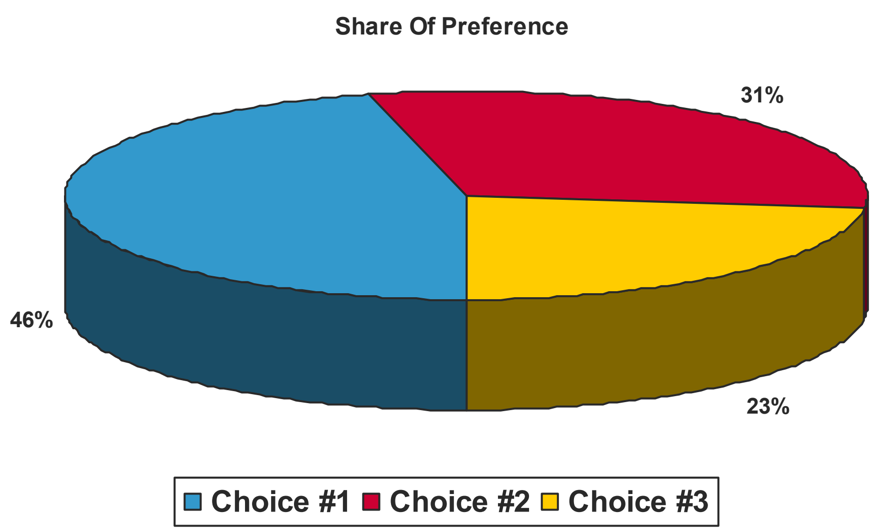
20% GHG reductions

<u>Choice #3</u>

Renewable energy program

30% price increase

30% GHG reductions

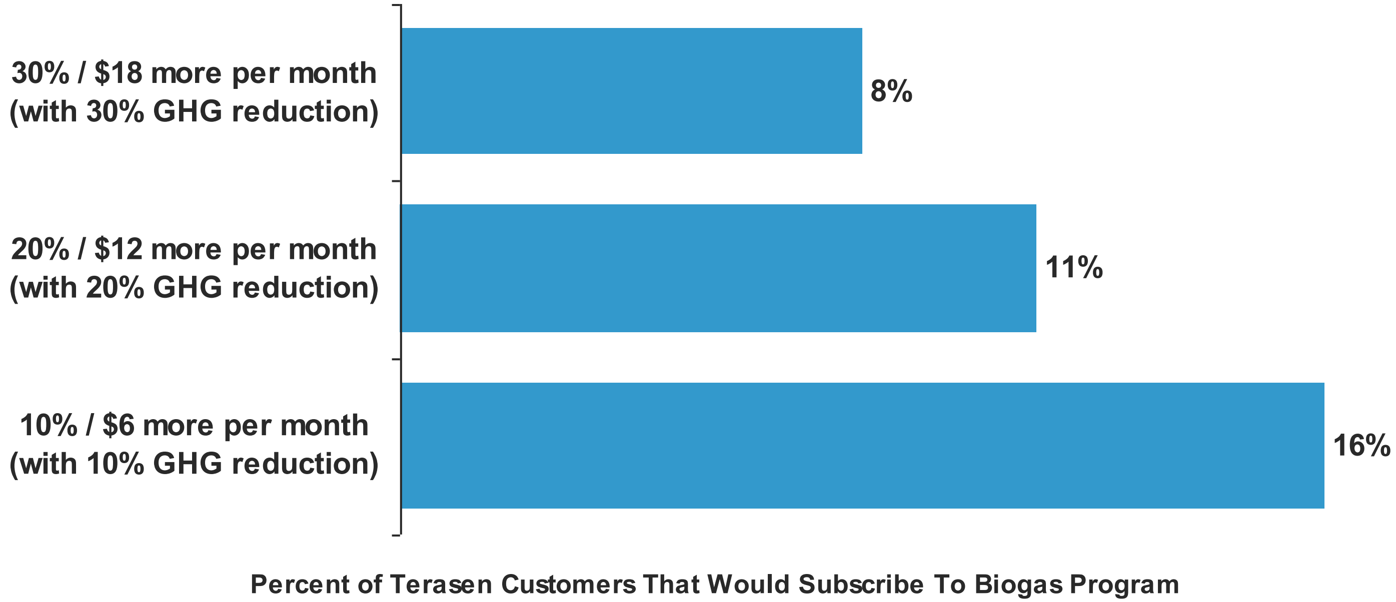


Base: The 56% of Terasen customers who are likely to sign up for a biogas program (n=445)

The reader should bear in mind that "none of the above" is not an option, because the model has already excluded those customers who would not sign up for the program.

Market Size Projections Based On DCM

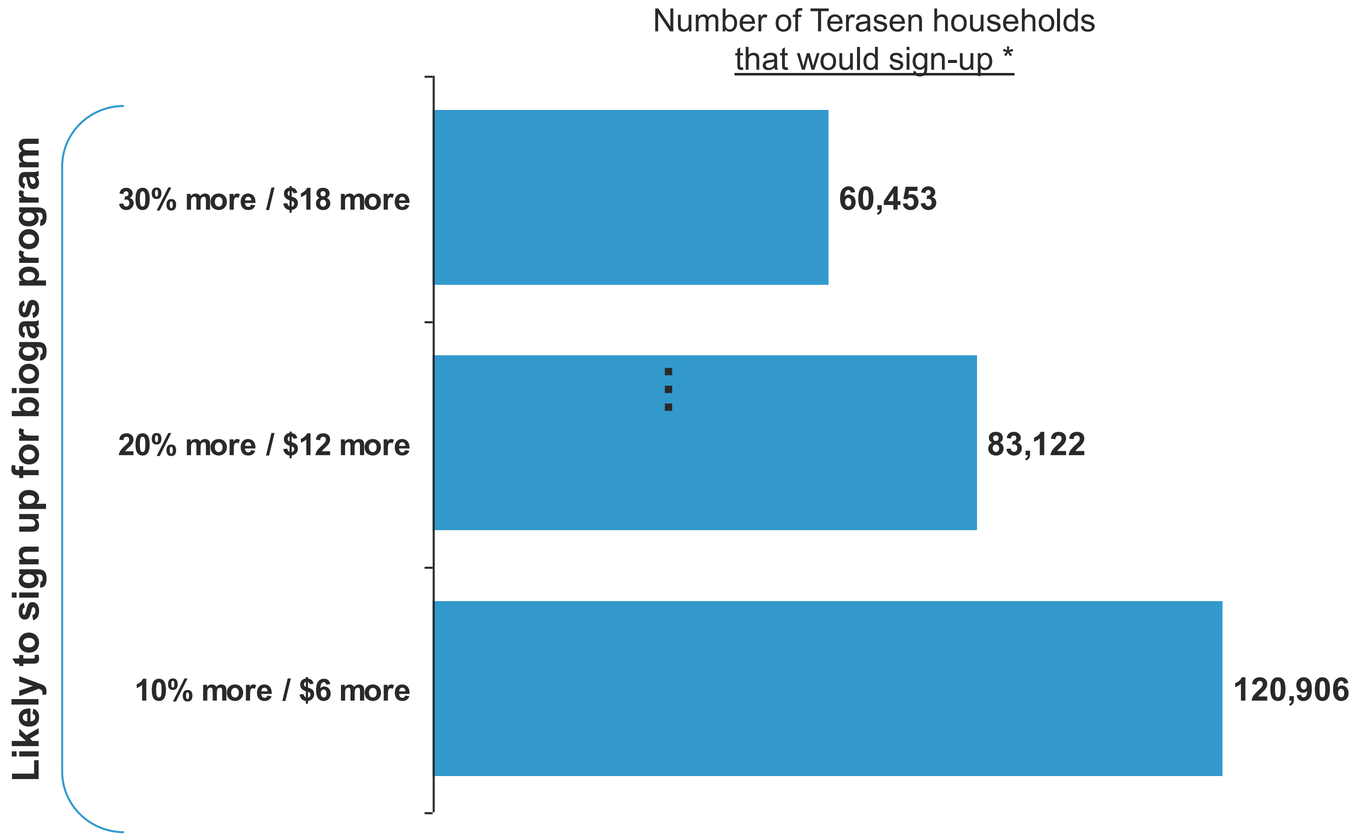
Next, the share of market percentages from the previous page are overlaid on top of those customers who are willing to spend at least $1.80 or more on a biogas program. At this point, we would strongly point out that "market share" and "share of preference" from a DCM are not the same. However, share of preference is the best estimate we have for predicting market share at these higher price levels. The figures below should be interpreted with caution.



Market share estimates derived by multiplying previous share of preference figures against percentage of residents who are willing to spend at least $1.80 more on a biogas program (34%).

Summary Of Market Potential (cont'd)

As a final step, these market share figures are converted into estimated number of households that would sign up and into potential revenue projections for Terasen.



Number of Terasen Gas households That Would Subscribe To Biogas Program

*Calculated from 755,660 TGI residential customers in BC, as per December 2009. Rate 1 customer counts supplied by Terasen.

** Per month. Computed by multiplying the number of households who would sign up against the average price increase.

Who's Most Interested In Biogas Program?

When investigating the differences between those who would sign up and those who would not, not many differentiators emerged. The demographic profile of residents interested in signing up for a biogas program is not very different from those who are not interested. Education and income appear to be two factors that separate someone who would not sign up for the program from someone willing to sign up and pay extra.

	Level of Interest in Biogas Program		
	Not likely to sign up	Very likely to sign up	Very likely to sign-up AND pay extra *
Base Size	(671)	(628)	(248)
INCOME			
Less than $15,000	6%	2%	2%
$15,000 to less than $35,000	21%	20%	16%
$35,000 to less than $60,000	29%	26%	25%
$60,000 to less than $100,000	34%	38%	40%
$100,000 or more	11%	15%	17%
EDUCATION			
Public or Elementary School	1%	<1%	0%
Secondary or High School	35%	29%	24%
Technical or CEGEP College	13%	19%	17%
Community College	24%	22%	25%
University	22%	23%	25%
Post Graduate	6%	7%	9%

* Based on those willing to pay extra 3% or $1.80 more per month

Impressions Of Terasen Gas

Before And After Energy Initiative Programs

Attitudes Toward Terasen

Residents were asked to rate Terasen on five image qualities related to the extent that it cares for:

- Its employees;
- Its role in the community;
- The environment;
- Making a profit; and,
- Re-investing in new environmentally-friendly technologies.

Residents rated Terasen on these areas at the beginning of the survey. Then they were presented with potential carbon offset and renewable energy programs that Terasen is considering. Following their exposure to various biogas initiatives under consideration, they were asked to rate Terasen a second time on the same above five elements, assuming Terasen could develop some type of a renewable biogas initiative like the ones presented in the DCM.

The results of this pre- and post-experimental approach to understanding the impact that a renewable biogas initiative would have on Terasen's corporate image are shown on the next page.

Impact Of Biogas Initiative On Views Of Terasen

Introducing a biogas Initiative will have positive effects on Terasen's corporate image. Residents would have a more positive view of Terasen as an organization that cares for the environment, its role in the community and in re-investing in new environmentally-friendly technologies.

The results below assume that the public has full knowledge of any renewable energy initiative that Terasen implements.

Exposure To Environmental Options (DCM)

Level of agreement that Terasen …	Before DCM (mean out of 10)	After DCM (mean out of 10)
Cares about employees	6.02	6.45
Cares about its role in the community	**5.74**	**7.18**
Cares about the environment	**5.80**	**7.74**
Cares about making a profit	7.23	7.38
Cares about re-investing in new environmentally-friendly technologies	**5.75**	**7.62**

Impact Of Biogas Initiative On Views Of Terasen

These positive effects on Terasen's corporate image does not apply to everyone, however. For example, within our lifestyle segments, the minority of Browns view this initiative very critically. A biogas program does little to enhance this segment's views of Terasen. Instead, they see this initiative as nothing more than another cash grab.

BROWNS

Exposure To Environmental Options (DCM)

Level of agreement that Terasen …	Before DCM (mean out of 10)	After DCM (mean out of 10)
Cares about employees	7.22	7.28
Cares about its role in the community	6.87	7.26
Cares about the environment	6.97	7.16
Cares about making a profit	**7.73**	**8.44**
Cares about re-investing in new environmentally-friendly technologies	7.18	7.08

Demographic Profile

About Residents

Demographics: By Customer Type

	Total	Customer Type		
		Terasen Customer	Indirect Customer	Do not use gas
Base Size	(1,401)	(799)	(200)	(352)
NATURAL GAS APPLIANCES				
Natural gas furnace	49%	76%	30%	3%
Natural gas hot water heater that heats your tap water	50%	72%	46%	5%
Natural gas boiler for home heating	11%	13%	20%	2%
Natural gas range, cook top, or oven	15%	21%	13%	1%
Natural gas fireplace	36%	50%	43%	3%
Natural gas clothes dryer	6%	7%	8%	1%
Natural gas barbecue that uses the gas service from your home	10%	15%	7%	2%
MAIN SPACE HEATING FUEL				
Natural gas	54%	80%	41%	4%
Electricity	32%	16%	44%	64%
Wood	3%	2%	1%	9%
Oil	2%	<1%	-	8%
Other	3%	1%	3%	9%
Don't know	6%	2%	12%	5%

Demographics: By Customer Type (cont'd)

	Total	Customer Type		
		Terasen Customer	Indirect Customer	Do not use gas
Base Size	(1,401)	(799)	(200)	(352)
HOME OWNERSHIP				
Home owner	71%	83%	52%	58%
Renter	28%	16%	46%	42%
Decline	1%	1%	3%	<1%
TYPE OF DWELLING				
Single-Detached house	59%	75%	24%	45%
Apartment Building / Condo	19%	5%	50%	34%
Row House / Townhouse / Condo Development	11%	11%	11%	10%
Mobile or Manufactured home	5%	6%	1%	7%
Suite contained within a house	3%	1%	13%	2%
Duplex / Triplex	3%	3%	2%	2%
Don't know / Decline	<1%	<1%	1%	<1%

Demographics: By Customer Type (cont'd)

	Total	Customer Type		
		Terasen Customer	Indirect Customer	Do not use gas
Base Size	(1,401)	(799)	(200)	(352)
AREA OF RESIDENCE				
Lower Mainland	56%	57%	74%	42%
Whistler	<1%	<1%	1%	1%
Interior	25%	30%	13%	19%
Vancouver Island	16%	10%	12%	35%
Sunshine Coast	2%	1%	1%	3%
Decline	2%	1%	2%	1%
AGE				
18 to 24 years	4%	3%	10%	2%
25 to 34 years	12%	10%	20%	11%
35 to 44 years	18%	18%	18%	17%
45 to 54 years	23%	24%	16%	24%
44 to 64 years	26%	28%	22%	26%
65 years or more	18%	17%	16%	20%

Demographics: By Customer Type (cont'd)

	Total	Customer Type		
		Terasen Customer	Indirect Customer	Do not use gas
Base Size	(1,401)	(799)	(200)	(352)
PEOPLE IN HOUSEHOLD				
One Person	17%	9%	26%	30%
Two People	43%	43%	43%	42%
Three to Five People	37%	43%	29%	27%
More than Five People	3%	4%	3%	1%
CHILDREN IN HOUSEHOLD				
Yes, have children	28%	34%	20%	20%
No, there are no children	72%	66%	80%	80%
EDUCATION				
Public or Elementary School	<1%	<1%	-	1%
Secondary or High School	32%	30%	29%	35%
Technical or CEGEP College	15%	15%	13%	17%
Community College	23%	25%	20%	20%
University	22%	22%	27%	19%
Post Graduate	7%	6%	9%	6%
Other	2%	1%	4%	2%

Demographics: By Customer Type (cont'd)

	Total	Customer Type		
		Terasen Customer	Indirect Customer	Do not use gas
Base Size	(1,401)	(799)	(200)	(352)
INCOME				
Less than $15,000	4%	3%	4%	7%
$15,000 to less than $35,000	21%	17%	25%	28%
$35,000 to less than $60,000	27%	26%	27%	29%
$60,000 to less than $100,000	35%	39%	34%	28%
$100,000 or more	12%	14%	11%	9%
GENDER				
Male	36%	32%	39%	44%
Female	64%	68%	61%	56%

Demographics: By Lifestyle Segment

	Lifestyles Segments							
	Dark Greens	Light Greens	Potential Switchers	Try Harders	Practicals	Extreme Practicals	Uncon-cerned	Browns
Base Size	(89)†	(161)	(53)†	(143)	(406)	(303)	(194)	(49)††
NATURAL GAS APPLIANCES								
Natural gas furnace	43%	55%	40%	50%	50%	49%	50%	47%
Natural gas hot water heater that heats your tap water	51%	52%	47%	50%	51%	51%	51%	39%
Natural gas boiler for home heating	11%	16%	19%	12%	10%	9%	9%	12%
Natural gas range, cook top, or oven	14%	16%	17%	14%	15%	17%	11%	10%
Natural gas fireplace	28%	37%	38%	36%	38%	39%	33%	29%
Natural gas clothes dryer	7%	8%	8%	6%	4%	4%	8%	4%
Natural gas barbecue that uses the gas service from your home	7%	14%	11%	7%	13%	11%	8%	6%
MAIN SPACE HEATING FUEL								
Natural gas	49%	60%	51%	58%	53%	53%	52%	49%
Electricity	35%	26%	38%	28%	32%	33%	33%	35%
Wood	6%	3%	2%	3%	3%	2%	6%	2%
Oil	1%	3%	4%	1%	3%	3%	1%	2%
Other	2%	1%	-	4%	3%	2%	2%	-
Don't know / Not sure	6%	6%	2%	5%	6%	5%	7%	12%

† Data based on sample sizes of less than 100 should be interpreted with caution.
†† Data based on sample sizes of less than 50 should be interpreted with extreme caution.

Demographics: By Lifestyle Segment (cont'd)

	Lifestyles Segments							
	Dark Greens	Light Greens	Potential Switchers	Try Harders	Practicals	Extreme Practicals	Uncon-cerned	Browns
Base Size	(89)†	(161)	(53)†	(143)	(406)	(303)	(194)	(49)††
HOME OWNERSHIP								
Home owner	60%	70%	64%	71%	74%	72%	70%	61%
Renter	40%	29%	34%	25%	25%	28%	28%	37%
Decline	-	1%	2%	4%	1%	-	2%	2%
TYPE OF DWELLING								
Single-Detached house	55%	58%	57%	57%	61%	63%	57%	49%
Apartment Building / Condo	29%	18%	19%	19%	19%	18%	16%	31%
Row House / Townhouse / Condo Development	7%	12%	9%	15%	10%	11%	9%	10%
Mobile or Manufactured home	6%	6%	8%	6%	5%	4%	9%	6%
Duplex / Triplex	2%	4%	-	3%	2%	2%	4%	-
Suite contained within a house	1%	2%	8%	2%	4%	3%	4%	4%
Don't know / Decline	-	1%	-	-	<1%	-	1%	-

† Data based on sample sizes of less than 100 should be interpreted with caution.
†† Data based on sample sizes of less than 50 should be interpreted with extreme caution.

Demographics: By Lifestyle Segment (cont'd)

	Lifestyles Segments							
	Dark Greens	Light Greens	Potential Switchers	Try Harders	Practicals	Extreme Practicals	Uncon-cerned	Browns
Base Size	(89)†	(161)	(53)†	(143)	(406)	(303)	(194)	(49)††
AREA OF RESIDENCE								
Lower Mainland	54%	58%	55%	57%	55%	54%	58%	55%
Whistler	-	1%	2%	-	1%	<1%	-	2%
Interior	26%	26%	28%	25%	25%	23%	25%	20%
Vancouver Island	17%	14%	15%	14%	17%	19%	13%	18%
Sunshine Coast	2%	1%	-	1%	2%	2%	2%	-
Decline	1%	1%	-	3%	1%	2%	2%	4%
AGE								
18 to 24 years	3%	3%	2%	4%	4%	4%	5%	8%
25 to 34 years	9%	9%	11%	15%	11%	13%	16%	12%
35 to 44 years	15%	17%	19%	16%	16%	19%	21%	22%
45 to 54 years	28%	26%	28%	22%	23%	20%	22%	20%
44 to 64 years	30%	28%	25%	26%	28%	27%	17%	18%
65 years or more	15%	17%	15%	18%	19%	16%	19%	18%

† Data based on sample sizes of less than 100 should be interpreted with caution.
†† Data based on sample sizes of less than 50 should be interpreted with extreme caution.

Demographics: By Lifestyle Segment (cont'd)

	Lifestyles Segments							
	Dark Greens	Light Greens	Potential Switchers	Try Harders	Practicals	Extreme Practicals	Uncon-cerned	Browns
Base Size	(89)†	(161)	(53)†	(143)	(406)	(303)	(194)	(49)††
PEOPLE IN HOUSEHOLD								
One Person	20%	19%	26%	16%	17%	15%	16%	31%
Two People	37%	49%	34%	48%	44%	44%	39%	39%
Three to Five People	43%	29%	40%	33%	36%	38%	42%	31%
More than Five People	-	3%	-	4%	4%	3%	4%	-
CHILDREN IN HOUSEHOLD								
Yes, have children	29%	21%	21%	27%	28%	31%	33%	20%
No, there are no children	71%	80%	79%	73%	72%	69%	67%	80%
EDUCATION								
Public or Elementary School	-	1%	-	-	-	1%	1%	2%
Secondary or High School	33%	28%	30%	32%	31%	28%	40%	43%
Technical or CEGEP College	18%	12%	13%	16%	15%	19%	13%	12%
Community College	18%	29%	36%	23%	21%	19%	26%	10%
University	23%	22%	11%	20%	25%	23%	14%	22%
Post Graduate	8%	7%	8%	6%	6%	8%	4%	8%

† Data based on sample sizes of less than 100 should be interpreted with caution.

†† Data based on sample sizes of less than 50 should be interpreted with extreme caution.

Demographics: By Lifestyle Segment (cont'd)

	Lifestyles Segments							
	Dark Greens	Light Greens	Potential Switchers	Try Harders	Practicals	Extreme Practicals	Uncon-cerned	Browns
Base Size	(89)†	(161)	(53)†	(143)	(406)	(303)	(194)	(49)††
INCOME								
Less than $15,000	2%	4%	4%	6%	3%	4%	8%	12%
$15,000 to less than $35,000	33%	20%	17%	16%	21%	19%	23%	27%
$35,000 to less than $60,000	20%	27%	32%	29%	27%	28%	26%	22%
$60,000 to less than $100,000	35%	37%	34%	36%	37%	35%	31%	27%
$100,000 or more	10%	12%	13%	13%	12%	14%	12%	12%
GENDER								
Male	34%	30%	38%	30%	37%	35%	38%	63%
Female	66%	70%	62%	70%	63%	65%	62%	37%
HOW RECEIVE BILL								
Receive bill directly from Terasen Gas	46%	63%	49%	58%	59%	58%	56%	51%
Pay gas bill indirectly	20%	11%	23%	13%	15%	14%	13%	12%
Does not use gas	29%	24%	26%	25%	24%	25%	24%	31%
Don't know	3%	3%	2%	4%	3%	2%	7%	6%

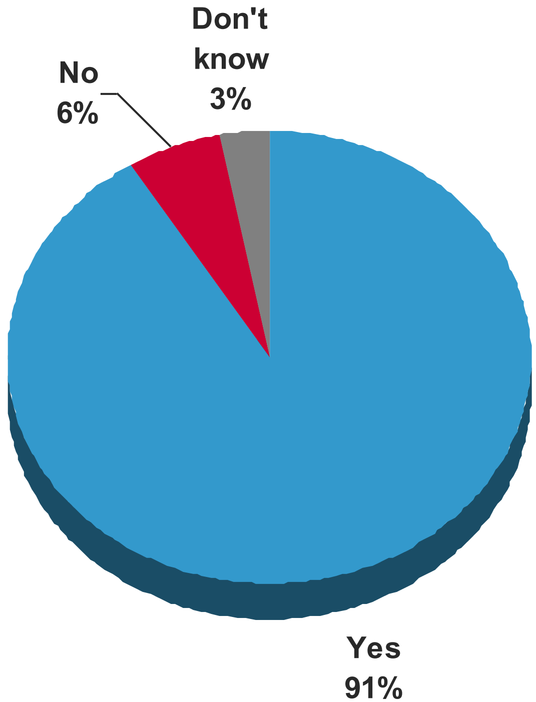
† Data based on sample sizes of less than 100 should be interpreted with caution.
†† Data based on sample sizes of less than 50 should be interpreted with extreme caution.

Commercial Customer Findings

Commercial Customers Also Open To Energy Conservation Programs

A similar proportion of commercial customers have taken steps to save energy as BC household residents. Also like residents, similar initiatives have been taken with reuse, reduce, recycle and efficient lighting the two most cited initiatives by both groups.

Whether Steps Taken To Save Energy



Base: Total respondents (n=500)

Steps Taken To Save Energy

	Total
Base: Total respondents who have taken steps to save energy at home	(453)
Re-using / reducing / recycling materials	78%
Energy efficient lighting	76%
Installed a programmable thermostat	50%
Weather stripping / caulking	40%
Installed timers for lighting	35%
Reduced water use	33%
Conducted energy saving awareness program for employees	31%
Insulated windows/ doors/ spaces	27%

QG1: Have you taken steps to save energy at this location?
QG2: What steps have you taken to save energy in your organization? (select all that apply)

Opinions On Biogas Initiative Very Positive

The level of support among the commercial customer base for Terasen's investment in a biogas program is strong and on par with residential support (both 67%). However, there is a higher proportion of commercial customers who feel Terasen should offer a biogas program (71% versus 65% of household residents).

Should Terasen Be Investing In Biogas

	Total
Base: Total respondents	(500)
Yes (8-10)	67%
Maybe (4-7)	23%
No (1-3)	3%
Decline	7%

Should Terasen Offer A Biogas Program

	Total
Base: Total respondents	(500)
Yes (8-10)	71%
Maybe (4-7)	22%
No (1-3)	2%
Decline	5%

QT2: (On a scale of 1 – Definitely not to 10 – Definitely) Does your organization support Terasen Gas investing in biogas projects?

QT3: (On a scale of 1 – Definitely not to 10 – Definitely) Do you think Terasen Gas should invest in offering a biogas program to its commercial customers?

Motivations For Signing Up

Since organizations are managed by individuals, it is not surprising that many of the reasons for enrolling in a biogas program are similar among commercial customers and residential customers.

Motivations For Signing Up (All Mentions)

	Total
Base: Total respondents that are very likely to sign up for a biogas program	(318)
Doing the right thing	76%
Preserving nature	74%
Providing for future generations	70%
Promoting new technologies	65%
Human health	61%
Supporting local farmers by providing income for their waste streams	58%
Supporting local developments	54%
Meeting Government Greenhouse Regulations	45%
Meeting Corporate Environmental Initiatives	36%

Most Important Motivation For Signing Up

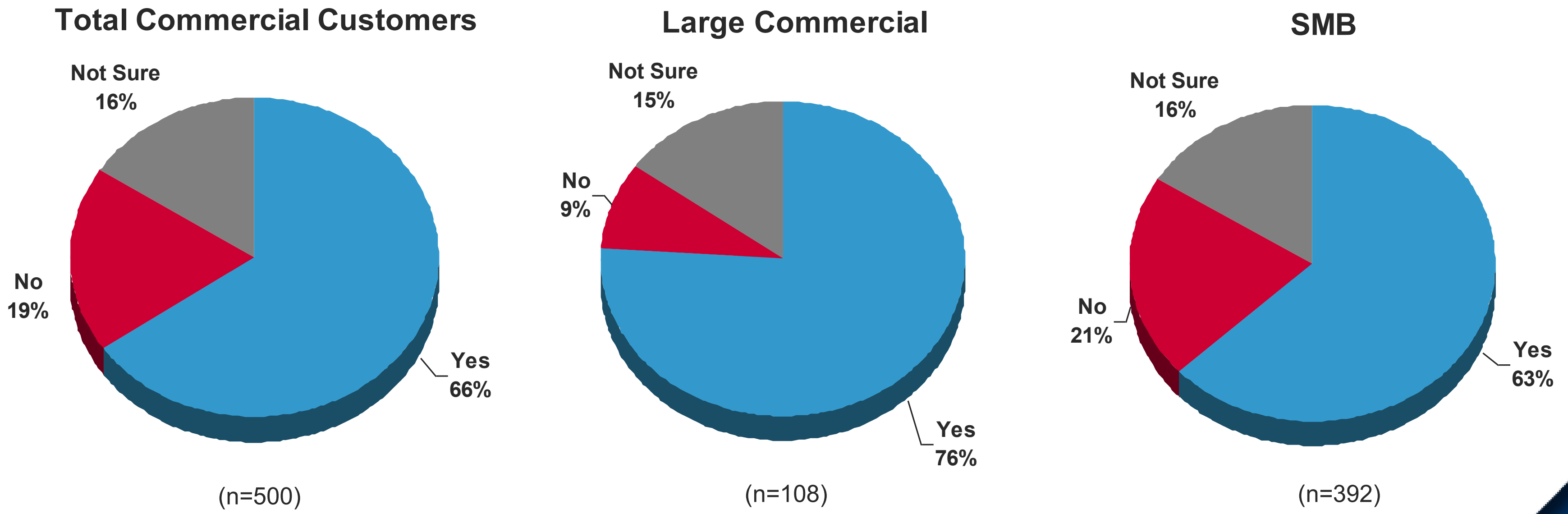
	Total
Base: Total respondents that are very likely to sign up for a biogas program	(318)
Doing the right thing	35%
Providing for future generations	13%
Preserving nature	12%
Supporting local farmers by providing income for their waste stream	9%
Human health	7%
Promoting new technologies	6%
Meeting Government Greenhouse Regulations	4%
Meeting Corporate Environmental Initiatives	6%
Don't know	2%

QT5: What, if any, would be the motivation for your organization to sign up for such a program ? (select all that apply)
QT6: And what would be your organization's most important motivation for signing up for such a program? (select one only)

Opinions On Carbon Offsets

Terasen Commercial customers are more knowledgeable about carbon offsets than BC residents. Also, Terasen's large commercial customers are more aware of this product than small commercial customers.

Awareness Of Carbon Offsets

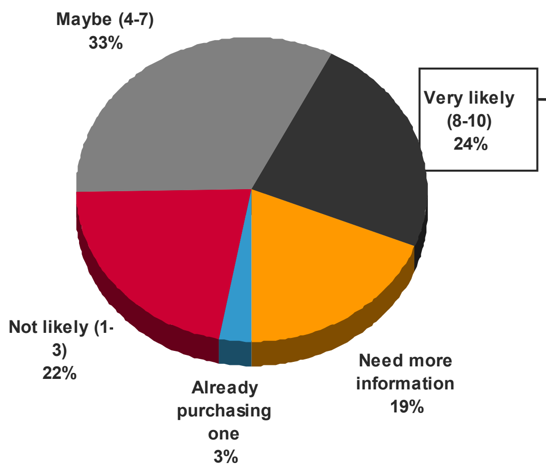


QC1: Have you ever heard of the term "carbon offset"?

Opinions On Carbon Offsets

Although they may be more familiar with carbon offsets, commercial customers are less likely to purchase carbon offsets than their residential counterparts (24% vs. 31% of residential customers). A greater proportion of these business customers are also undecided about who should be offering these offsets – whether it is a local utility provider or a third party.

Likelihood Of Purchasing Carbon Offsets



Base: Total respondents (n=500)

Preferred Source

	Total
Base: Total respondents who are extremely likely to purchase a carbon offset in order to reduce their environmental footprint	(120)
Your local utility provider	42%
A 3rd-party provider that supports projects in BC	13%
A 3rd-party provider that supports projects outside BC	2%
Need more information / Don't know	43%

QC2: (On a scale of 1 – Not at all likely to 10 – Extremely likely) Knowing this information, how likely would your organization be to purchase a carbon offset for its natural gas use in order to reduce your organizations environmental footprint? (select one only)
QC3: Would your organization prefer to purchase an offset through… (select all that apply)

Carbon Offsets: Preferred Project Investments

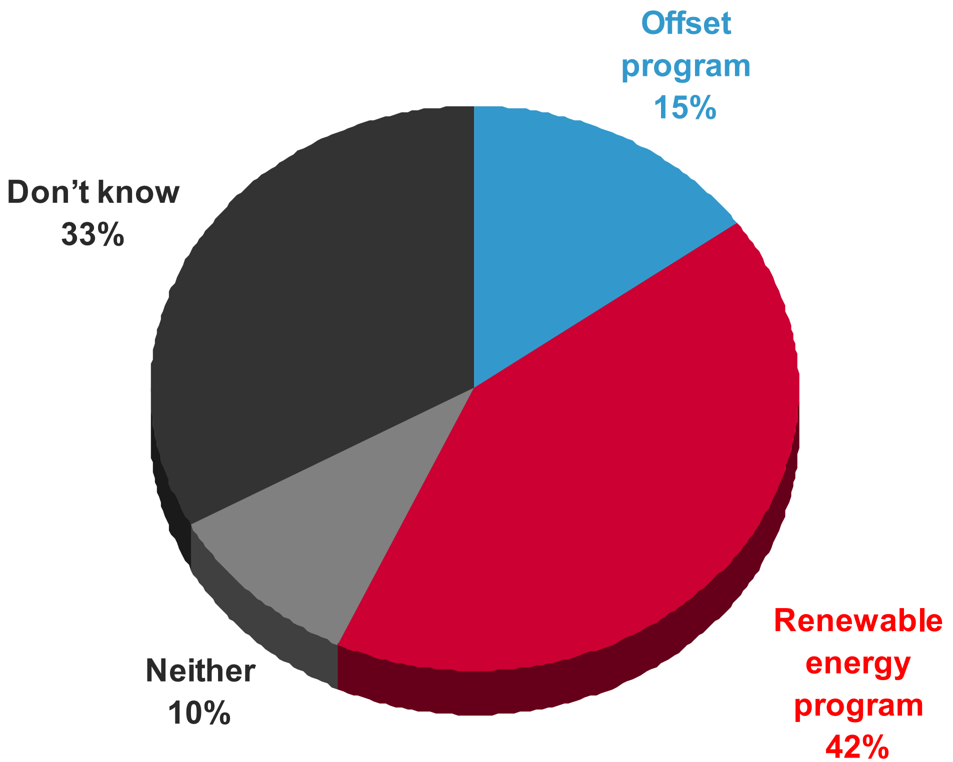
If Terasen were to invest in carbon offset projects, commercial customers would like to see Terasen support projects related to alternative energy sources. These include solar, wind and geothermal power.

	Total
Base Size	(500)
Solar power - generate energy from sunlight	68%
Wind power - use wind to create electricity	67%
Geothermal power - energy extracted from the ground for heating	61%
Environmental buildings - make buildings more energy efficient	57%
Forestation - plant trees which absorb carbon dioxide	53%
Efficient lighting- replace light bulbs with fluorescent lamps	48%
Fuel efficiency - burn a particular fuel more efficiently	47%
Fuel substitution - switch to a fuel that emits less carbon	38%
Public transportation - subsidize or encourage the use of public transport	37%
Heat-electricity cogeneration - create electricity and heat together	34%
3rd party biogas projects - within BC	31%
Energy from biomass - burn wood waste to generate electricity	29%
3rd party biogas projects - outside BC	10%
No preference	9%

QC5: What types of offset projects would your organization want to see Terasen Gas invest in outside of its own renewable energy projects? (select all that apply)

Carbon Offset Versus Renewable Energy Programs

When asked directly whether they would prefer Terasen to introduce a biogas program or a carbon offset program, biogas is favoured approximately three-to-one by commercial customers. It is important to point out, however, that one-third of this market is undecided. Many of these customers wanted more information beyond the program descriptions that were provided to them in this survey.

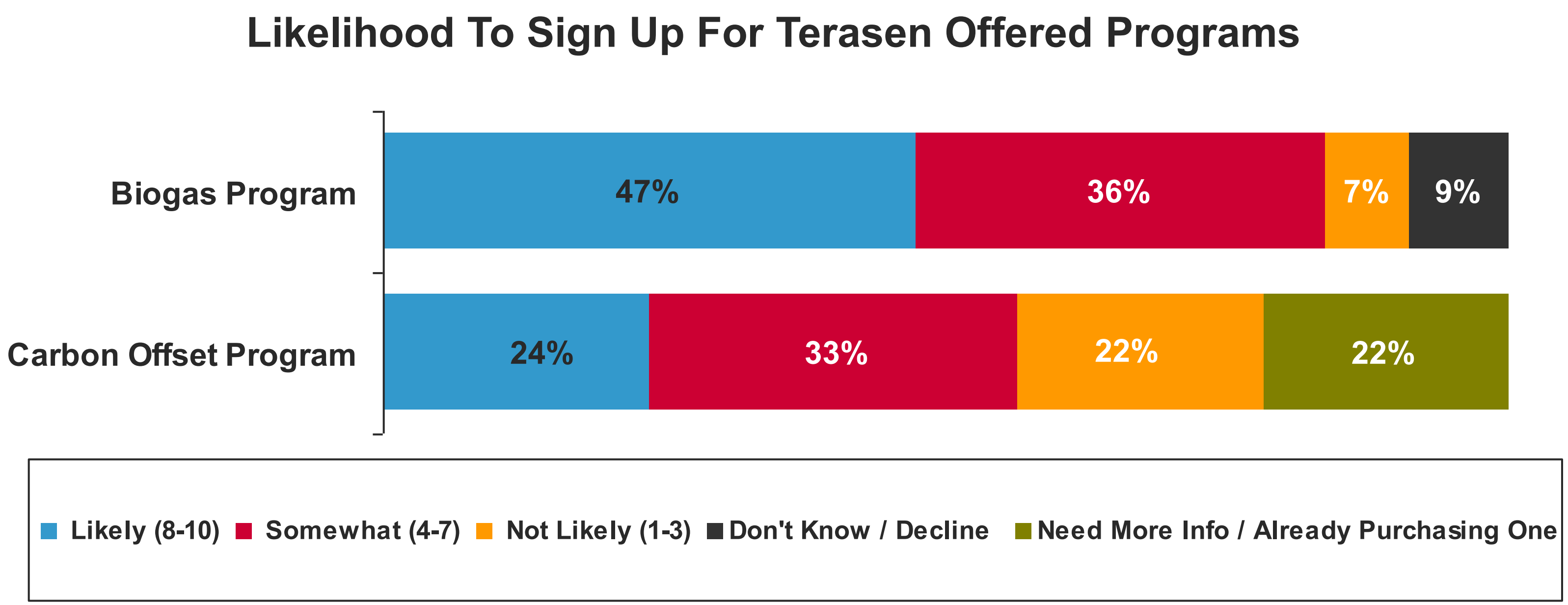


Base: Total respondents (n=500)

QC4: Which of these two programs would your organization be more inclined to see Terasen Gas introduce, if it were to do so? (select one only)

Commercial Customers More Likely To Sign Up For Biogas

Forty-seven percent of commercial customers indicate they are likely to sign up for a biogas program, in contrast to 24% for a carbon offset program. Similar to the resident population, a biogas program would appeal to a bigger potential market. Consequently, the next section of the report will focus on the market potential of a biogas program. These projections will be based on the 47% of customers who indicate a strong likelihood to sign up for biogas.



Base: Total respondents (n=500)

QT4: (On a scale of 1 –Not very likely to 10 – Very likely) All things being equal, if Terasen Gas offered a biogas program, how likely would your organization be to sign up?

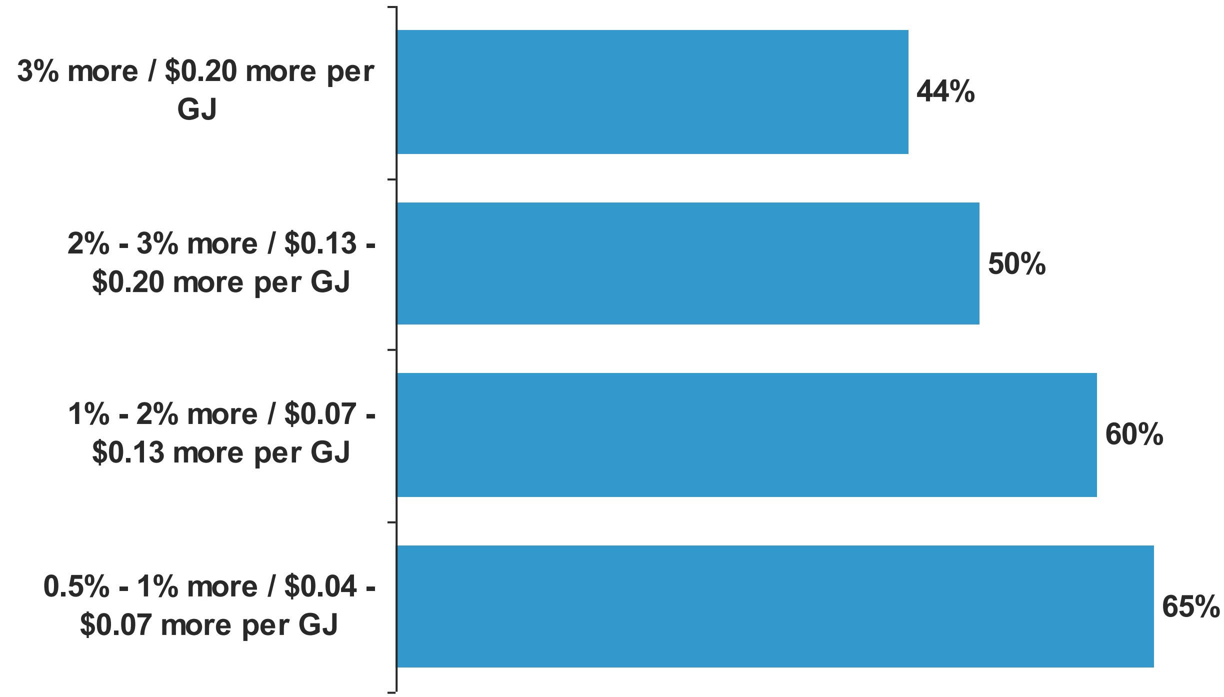
QC2: Knowing this information, how likely would your organization be to purchase a carbon offset for its natural gas use in order to reduce your organization's environmental footprint?

Estimating Potential Market Share

For Biogas Program

Market Reaction To Price Increases

In this next section, we undertake the same market projection exercise as with the residential customers. Overall, commercial customers are much more apprehensive than residential customers when it comes to supporting a biogas program, when there is a universal price increase associated with it. Less than half of customers would support this concept if it meant an universal increase of 3% or more.



Percent of Terasen Commercial Customers Who Would Support Program at specified price point

QP1A: If your organization had to pay 3% more than the current commodity price of natural gas, would your organization support or would your organization not support such a biogas program?
QP1B / QP2A: If your organization had to pay 2% more than the current commodity price of natural gas, would your organization support or would your organization not support such a biogas program?
QP2B / QP3A: … pay 1% more than the current commodity price of natural gas…?
QP3B: …pay 0.5% more than the current commodity price of natural gas…?

DCM Simulation – With Three Pricing Levels

At the higher price points of 10%, 20% and 30% gas bill increases, the share of preference for each option is similar to that found among residential customers. Share of preference is derived from a Discrete Choice analytic model that also factored in a proportionate GHG reduction level with each pricing increase..

Choice #1

Renewable energy program

10% price increase

10% GHG reductions

Choice #2

Renewable energy program

20% price increase

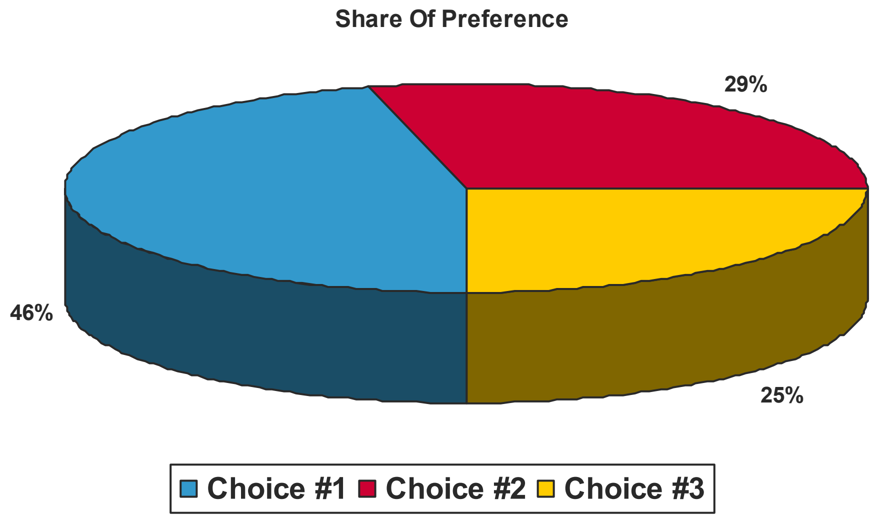
20% GHG reductions

Choice #3

Renewable energy program

30% price increase

30% GHG reductions

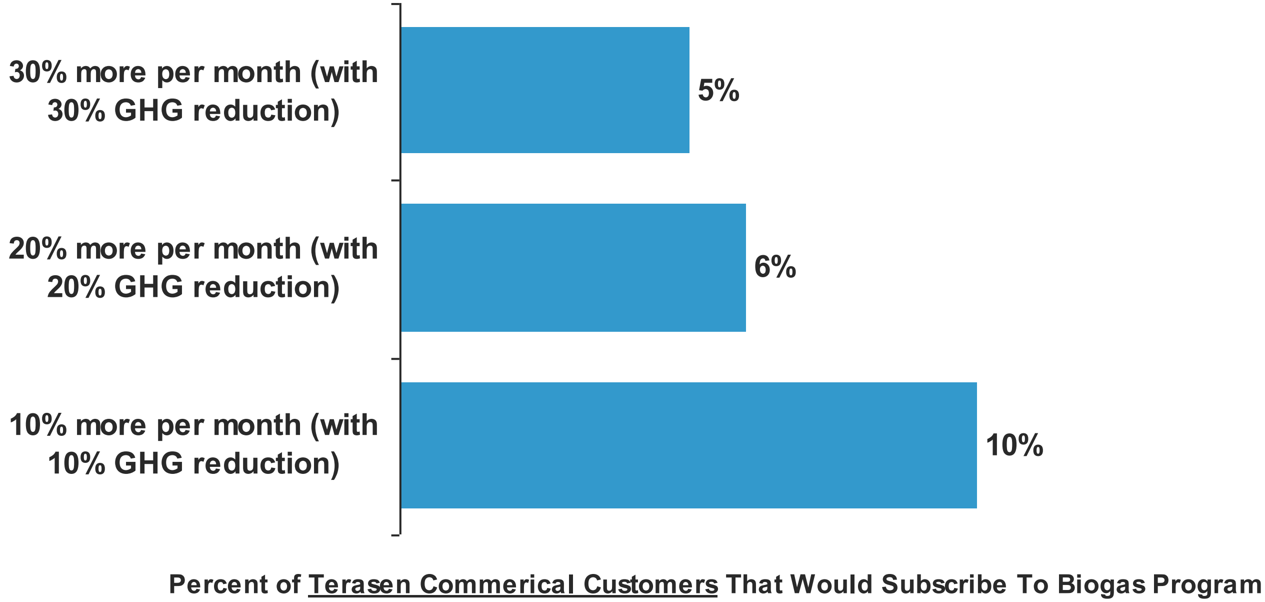


Base: The 47% of Terasen commercial customers Who Are Likely To Sign Up For A Biogas Program (n=237)

The reader should bear in mind that "none of the above" is not an option, because the model has already excluded those customers who would not sign up for the program.

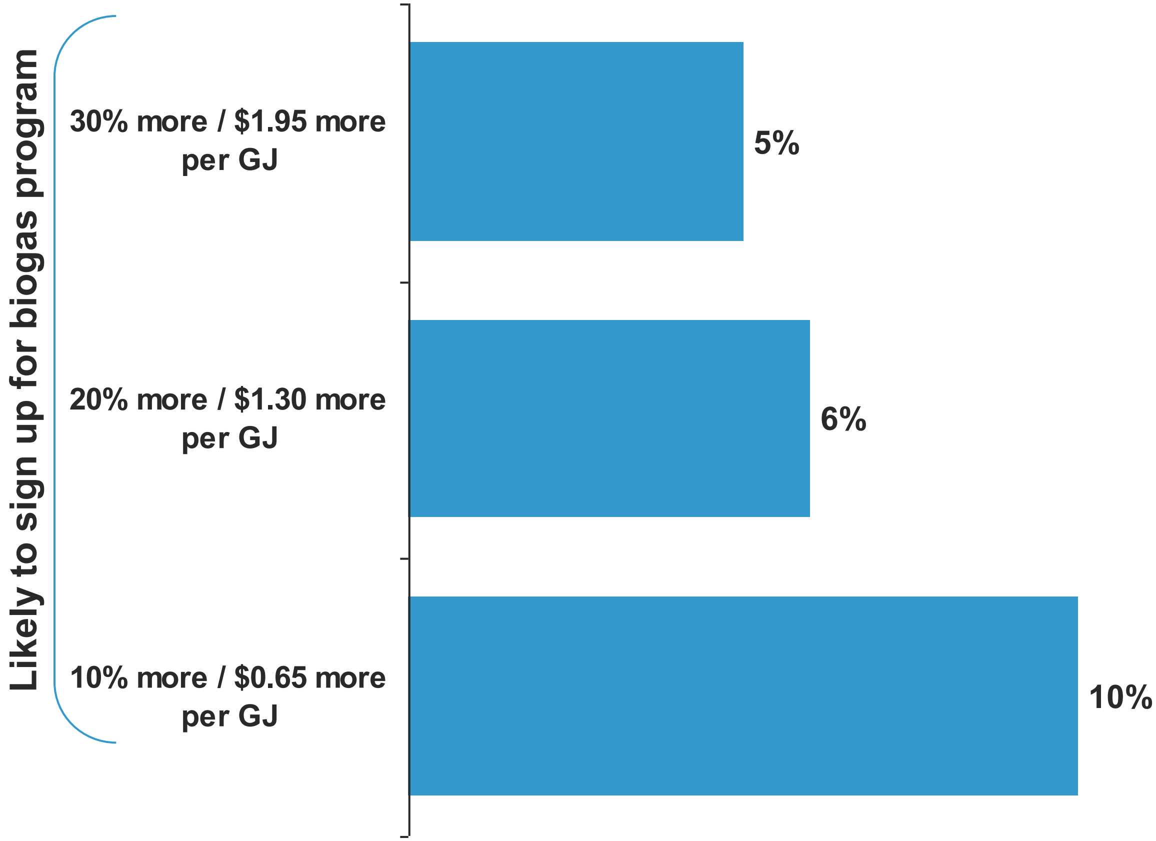
Market Size Projections Based On DCM

Once again, we overlay the share of market percentages from the previous page against those customers who are willing to support a 3% universal price increase for a biogas program. At this point, we would strongly point out that "market share" and "share of preference" from a DCM are not the same. However, share of preference is the best estimate we have for predicting market share at these higher price levels. The figures below should be interpreted with extreme caution.



Market share estimates derived by multiplying previous share of preference figures against percentage of customers who are willing to spend at least 3% more on a biogas program (21%).

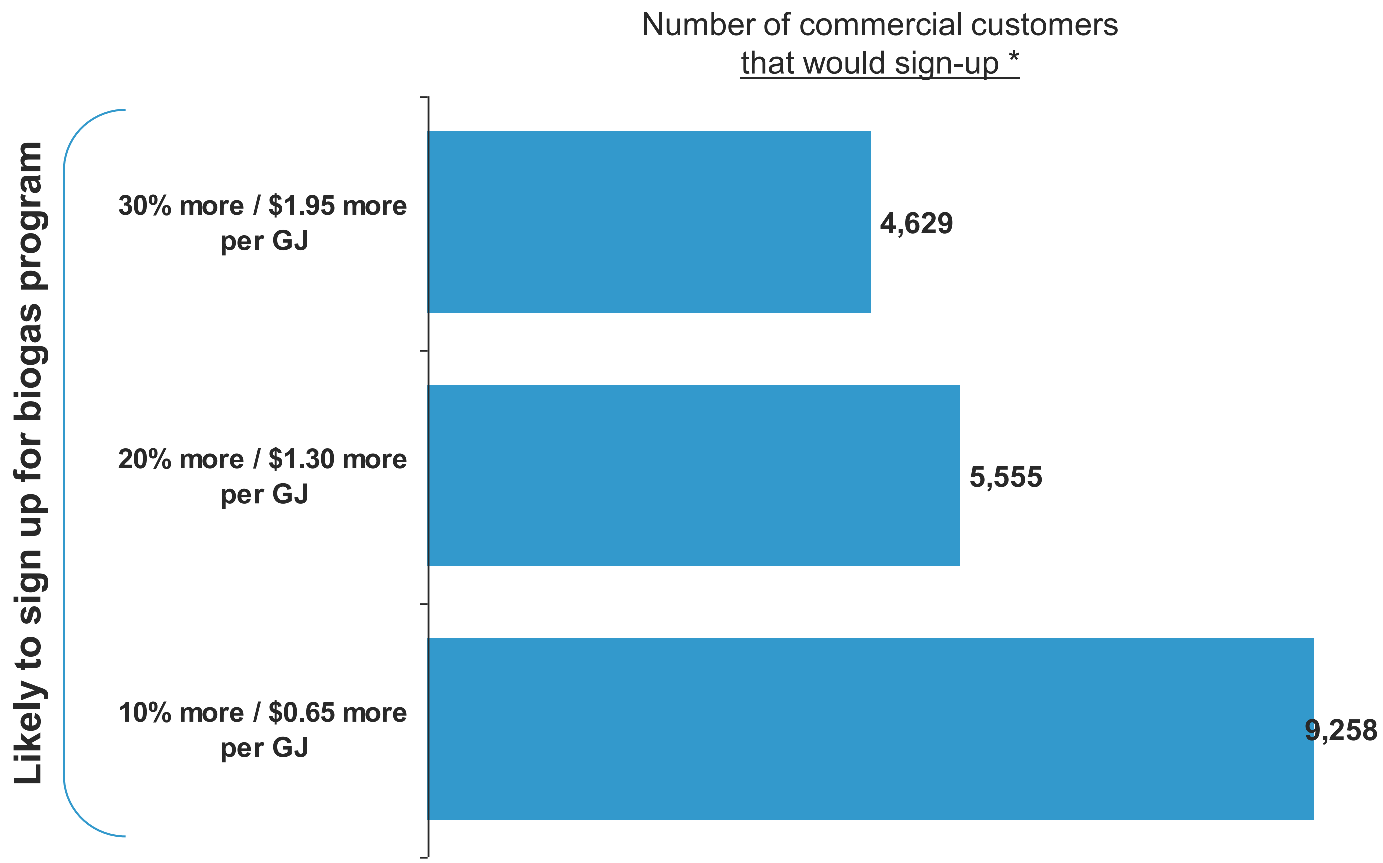
Summary Of Market Size (Maximum Potential)



Note: Based on share of preference. With GHG reductions factored in.

Percent of <u>Terasen Commercial Customers</u> That Would Subscribe To Biogas Program

Summary Of Market Size (Commercial Estimates)

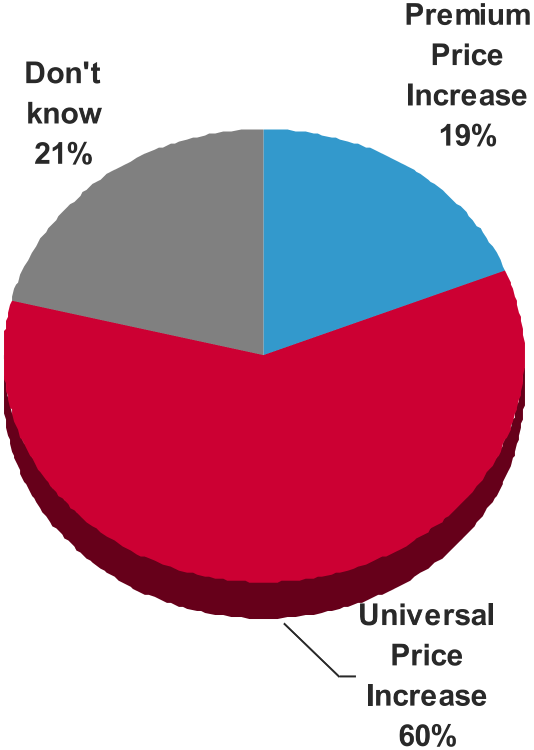


Number of Terasen Commercial Customers That Would Subscribe To Biogas Program

* Calculated from 92,579 commercial customers, as per customer counts supplied by Terasen.

Price Premiums Versus Universal Price Increase

Commercial customers interested in a biogas program were asked directly whether they would prefer to have a Terasen biogas program funded through a universal price increase (borne by all consumers) or through price premiums only for those who enroll in the program. Unlike residents who were unable to provide a conclusive assessment of funding options, commercial customers came out strongly in support of a universal price increase (supported by 60% of commercial respondents). Nineteen percent supported a premium price increase and 21% said they did not know. Please note that 56% of commercial customers were not asked this question because they indicated they were unlikely to subscribe to a biogas program.



Base: Total respondents who are likely to sign up for biogas program (n=237)

QP1: The costs for a biogas program can be offered to consumers in one of two ways. Which way would you prefer to see Terasen offer this program, if it were to do so? (select one only)


Signing Up For Biogas

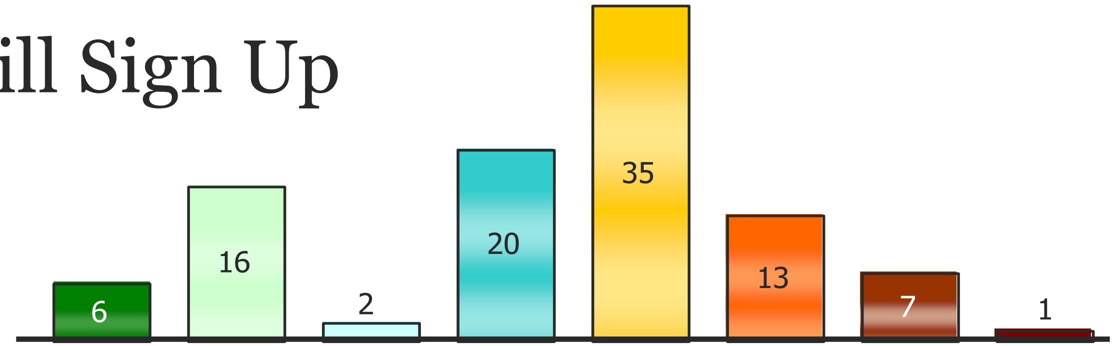
Who's Most Interested In Biogas Program?

The commercial customers segments that are most likely to sign up for a biogas program include those who have participated in past energy programs, those organizations with only one location (as opposed to multiple locations), and those who express concern for the environment.

	Level of Interest in Biogas Program		
	Not likely to sign up	Very likely to sign up	Very likely to sign-up AND pay extra *
Base Size	(219)	(237)	(73)
PAST BEHAVIOUR			
Have taken steps to save energy in past	88%	**95%**	92%
NUMBER OF OFFICE LOCATIONS			
One	55%	**66%**	**63%**
Multiple	**44%**	34%	37%
CONCERNED FOR:			
Current state of environment	47%	**63%**	59%
Future state of environment	63%	**79%**	**77%**
Global warming / climate change	44%	**69%**	**62%**
Greenhouse gas emissions	44%	**61%**	**62%**
Greenhouse gas regulations	44%	**57%**	52%
Loss of oxygen producing forests	55%	**71%**	**69%**
Government / Industry leadership on environmental issues	50%	**64%**	56%
Access to alternative energy solutions	52%	**65%**	58%

* Based on those willing to pay extra 3% per month

Green Businesses Will Sign Up



Top two box scores taken

	Total (n=499)	1.Dark Greens (n=32*)	2.Light Greens (n=79)	3.Potential Switchers (n=9**)	4.Try Harders (n=100)	5.Practicals (n=176)	6.Extreme Practicals (n=64)	7.Unconcerned (n=35*)	8.Browns (n=4**)
QT2. Does your organization support Terasen Gas investing in biogas projects?	49			44	61	45	36		25
QT3. Do you think Terasen Gas should invest in offering a biogas program to its commercial customers?	53	69	63	44	63	50	36		25
QT4. All things being equal, if Terasen Gas offered a biogas program, how likely would your organization be to sign up?	31	50	48	22	35	24	22		25
QC2. Knowing this information, how likely would your organization be to purchase a carbon offset for its natural gas use in order to reduce your organization's environmental footprint?	13		25	11	13	9	9	6	0

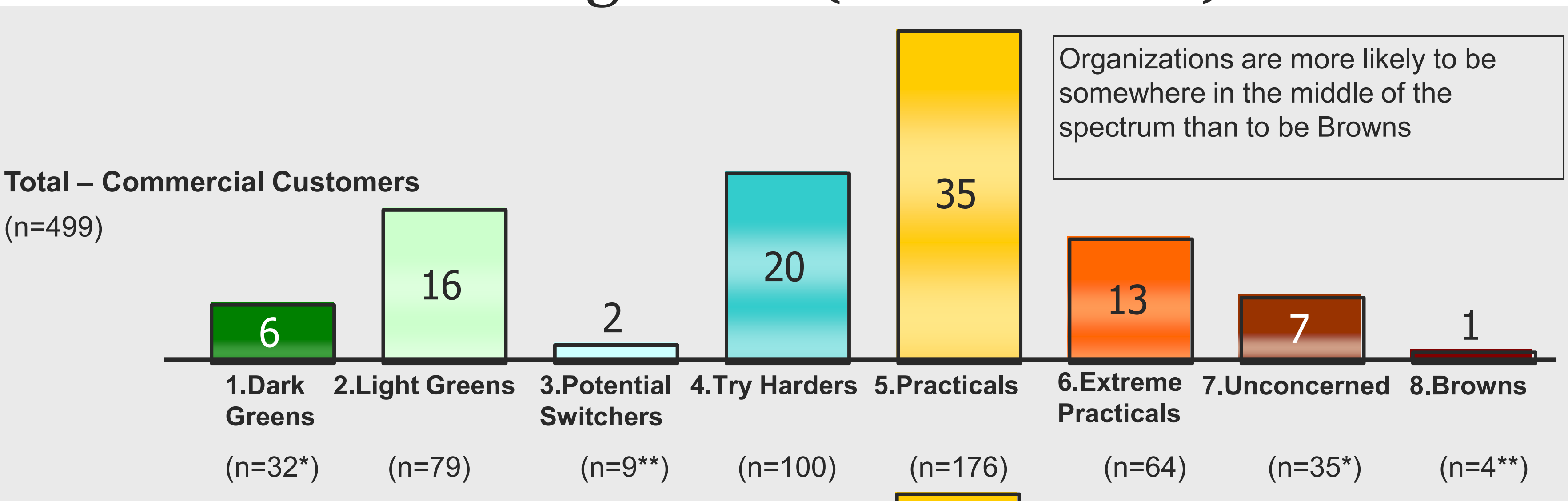
Try Harders are practical but like the idea of environmentally conscious business practices. They tend to rate the Biogas program highly, however, may not sign up for practical reasons.

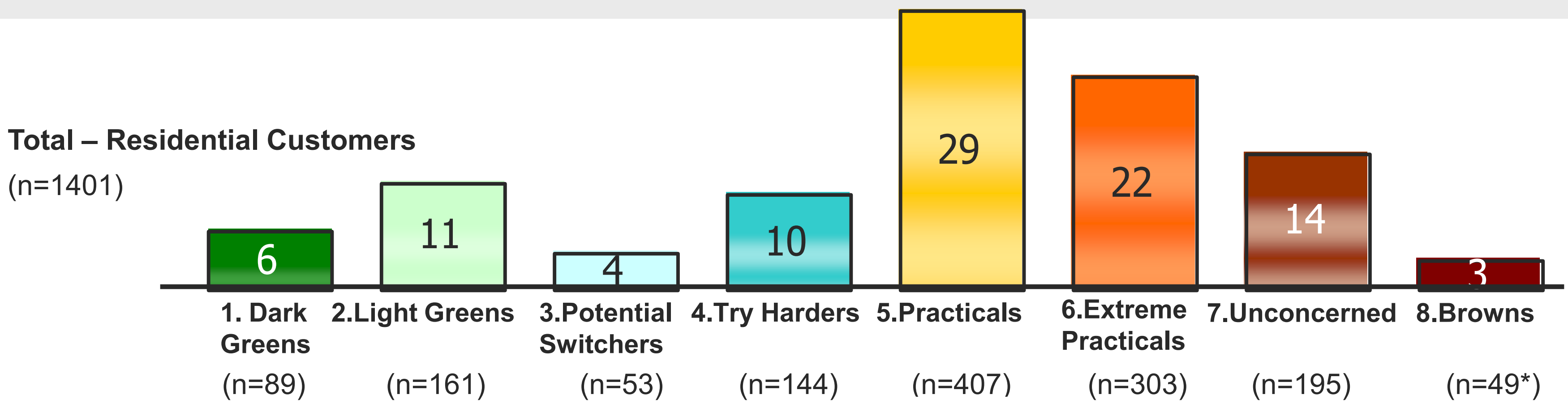
* Caution= small base size

** Caution= base size too small for analysis

Percentages with n<30 in the denominator greyed out

Business Practice Segments (Distribution)












* Caution= small base size

** Caution= base size too small for analysis

What's Driving Them To Sign Up?

It should be noted that the previous commitment segments are attitudinal based. When cross-tabulated against firmographic variables, we did not find any linkages between attitudes and firmographics. So, to better understand what other drivers might motivate commercial customers to sign up for a Terasen biogas program, we refer to the Discrete Choice Model.

For commercial customers, it's all about reducing GHG levels. Similar to BC residents, commercial customers are not as concerned with the type of program as they are with the idea of reducing their carbon footprint. Price is clearly a factor for businesses, however, it does not appear to play as prominent a role in their preference for various options within the Discrete Choice Model, as it did for residents.

Although GHG reduction is a critical driver for commercial customers, it should be noted that these customers want to see a program that will offer significant reductions in their carbon footprint. Higher GHG reductions are more attractive however, to customers, there is little difference between a 10% and a 20% GHG reduction.

When presented with various choices during the DCM exercise, commercial customers gravitated more towards a biogas program than a carbon offset program. However, this is due partly to the fact that the results are filtered only for those respondents who expressed a high interest in a biogas program of some form.

The utility values behind the Discrete Choice model for commercial customers are presented on the next page. These utility values provide a read of the relative importance of the attributes in the model. The higher the utility value, the higher it is in terms of importance to respondents.

What's Driving Them To Sign Up? (cont'd)

Summary of DCM Attribute Importance

Utility Values	Total
Energy Initiative	6.5
Percent Reduction In Green House Gas Emissions	16.3
Effect On Monthly Gas Bill	11.4

Reduction In Green House Gas Emissions (Utility Values)

Utility Values	Total
10%	10.0
20%	10.0
30%	15.2
50%	21.5
80%	23.8
100%	26.3

Effect On Monthly Gas Bill (Utility Values)

Utility Values	Total
Current Price + 10%	21.4
Current Price + 20%	16.8
Current Price + 30%	10.0

Energy Initiative (Utility Values)

Utility Values	Total
Renewable Energy Program	16.5
Carbon Offset Program	10.0

Base: The 47% of Terasen Commercial Customers who are likely to sign up for a biogas program

tns

Impressions Of Terasen Gas

Before And After Energy Initiative Programs

Attitudes Toward Terasen

Commercial customers were asked to rate Terasen on five image qualities related to the extent that it cares for:

- Its employees;
- Its role in the community;
- The environment;
- Making a profit; and,
- Re-investing in new environmentally-friendly technologies.

Customers rated Terasen on these areas at the beginning of the survey. Then they were presented with potential carbon offset and renewable energy programs that Terasen is considering. Following their exposure to various biogas initiatives under consideration, they were asked to rate Terasen a second time on the same above five elements, assuming Terasen could develop some kind of a renewable biogas initiative like the ones presented in the DCM.

The results of this pre- and post-experimental approach to understanding the impact that a renewable biogas initiative would have on Terasen's corporate image are shown on the next page.

Impact Of Biogas Initiative On Views Of Terasen

A similar impact is observed between commercial and residential customers when it comes to the effects of a biogas program on Terasen's corporate image. Implementing such a program will improve commercial customer's impressions of Terasen's role in the community, concern for the environment and commitment to re-investing in new environmentally-friendly technologies.

Level of agreement that Terasen …	Before DCM (mean out of 10)	Exposure To Environmental Options (DCM)	After DCM (mean out of 10)
Cares about employees	6.68	→	7.23
Cares about its role in the community	**6.34**	→	**7.91**
Cares about the environment	**6.40**	→	**8.22**
Cares about making a profit	7.70	→	7.79
Cares about re-investing in new environmentally-friendly technologies	**6.38**	→	**8.29**

Firmographic Profile

Firmographics

	TOTAL	TOTAL CONSUMPTION		TERASEN OR GAS MARKETER	
		LARGE COMMERCIAL	SMALL COMMERCIAL	TERASEN	GAS MARKETER
Base Size	(500)	(108)	(392)	(279)	(221)
ORGANIZATION SECTOR:					
Retail	18%	3%	**22%**	20%	15%
Industrial	10%	8%	10%	8%	11%
Commercial	10%	7%	11%	7%	**14%**
Construction	9%	4%	**11%**	9%	10%
Hospitality	8%	**12%**	7%	10%	5%
Institutional	8%	**17%**	6%	10%	6%
Office	7%	9%	6%	6%	8%
Food	7%	5%	7%	8%	5%
Government Organization	6%	13%	4%	5%	6%
Agriculture	4%	**8%**	2%	4%	4%
Auto Repair / Gas Station	3%	1%	4%	3%	4%
Recreation	2%	**6%**	2%	3%	2%
Wood & Forest	1%	1%	1%	<1%	1%
Don't Know / Decline	9%	7%	9%	8%	10%

Firmographics (cont'd)

	TOTAL	TOTAL CONSUMPTION		TERASEN OR GAS MARKETER	
		LARGE COMMERCIAL	SMALL COMMERCIAL	TERASEN	GAS MARKETER
Base Size	(500)	(108)	(392)	(279)	(221)
HEATING FUEL TYPE:					
Natural Gas	77%	79%	77%	77%	77%
Electricity	16%	18%	16%	15%	18%
Bottled Propane	1%	-	2%	1%	1%
Oil	1%	-	1%	1%	-
Piped Propane	<1%	-	1%	1%	-
Wood	<1%	-	1%	1%	-
Other	1%	-	1%	1%	-
Don't Know / Not Sure	3%	4%	3%	3%	3%
BUSINESS OWNER / EMPLOYEE:					
Owner	49%	28%	**54%**	48%	49%
Employee	48%	**70%**	41%	49%	46%
Decline	4%	2%	4%	3%	5%
OFFICE LOCATIONS:					
Lower Mainland	54%	**64%**	52%	31%	**84%**
Interior	29%	20%	**32%**	**42%**	13%
Vancouver Island	13%	13%	13%	**22%**	1%
Sunshine Coast	1%	1%	1%	**2%**	-
Decline	3%	2%	3%	3%	2%

Firmographics (cont'd)

	TOTAL	TOTAL CONSUMPTION		TERASEN OR GAS MARKETER	
		LARGE COMMERCIAL	SMALL COMMERCIAL	TERASEN	GAS MARKETER
Base Size	(500)	(108)	(392)	(279)	(221)
MULTIPLE OFFICES:					
Yes	39%	**61%**	33%	37%	42%
No	61%	39%	**67%**	63%	58%
Don't Know	<1%	-	1%	-	1%
NUMBER OF EMPLOYEES:					
1 - 5	32%	14%	**37%**	31%	33%
6 - 10	14%	6%	**17%**	16%	12%
11 - 25	17%	14%	18%	17%	18%
26 - 50	9%	7%	10%	10%	9%
51 - 100	8%	**15%**	6%	8%	9%
101 - 200	6%	**19%**	3%	5%	8%
More than 200	10%	**25%**	6%	12%	9%
Decline	2%	2%	2%	1%	3%

Firmographics (cont'd)

	TOTAL	TOTAL CONSUMPTION		TERASEN OR GAS MARKETER	
		LARGE COMMERCIAL	SMALL COMMERCIAL	TERASEN	GAS MARKETER
Base Size	(500)	(108)	(392)	(279)	(221)
TOTAL 2008 REVENUE:					
Less than $100,000	8%	1%	**10%**	9%	7%
$100,000 to less than $500,000	19%	8%	**22%**	18%	20%
$500,000 to less than $1,000,000	10%	5%	**12%**	12%	8%
$1,000,000 to less than $5,000,000	19%	23%	18%	19%	19%
$5,000000 to less than $10,000,000	4%	4%	5%	5%	4%
$10,000,000 to less than $25,000,000	6%	**14%**	3%	7%	5%
$25,000,000 or more	6%	**12%**	4%	4%	9%
Don't know / decline	28%	33%	27%	28%	29%

Appendix To The Methodology

Appendix To The Methodology

Overview

A total of 1,401 online interviews was conducted between November 23 and December 4, 2009 with a sample of British Columbia residents. In addition to these residential interviews, 500 interviews were conduced with commercial customers of Terasen from December 14, 2009 to January 22, 2010.

Results obtained from this survey provide valuable insights into understanding perceptions of Terasen and feature preferences for a renewable biogas program.

Sample Frame And Design

The samples used in this survey were drawn from two different sources. TNS' Canadian online adult panel was used to intercept BC residents. All BC communities were sampled. A quota cell design was used for this survey to ensure that a specific sampling level was achieved with respect to Terasen's own customers and non-customers. The number of completed interviews for each quota group are outlined below.

Sample Design

	Target Quota	Actual Interviews
	#	#
Terasen Gas customers (receive gas bill directly from TG)	800	799
Indirect customers (pay gas bill indirectly through rent or strata fees)	200	200
Non-customers (does not use gas at home)	100	352
Residents who don't know their energy source	-	50
Total	1,000	1,401

For the commercial study, the sampled was drawn from Terasen's customer database. Five hundred random interviews were conducted, without any quota requirements.

Appendix To The Methodology (cont'd)

Respondent Selection And Qualification

Respondents were selected differently for the two studies. On the residential side, respondents were randomly selected from TNS' online panel. This includes both gas users and non-users. On the commercial survey, respondents were restricted to Terasen customers and drawn randomly from Terasen's database. On both studies, respondents who work for a utility, gas marketer, the media, a research or advertising firm, were screened out of the study.

Questionnaire Development

The residential questionnaire was developed by TNS Canadian Facts in consultation with Terasen Gas. Prior to the start of interviewing, a pretest was conducted over the first weekend of field to ensure the workability of the questionnaire and to finalize question sequencing.

The commercial questionnaire is almost identical to the residential questionnaire with slight modifications.

Data Collection

Residential respondents were recruited from TNS' online panels and directed to the survey site to complete the survey. The results of the fieldwork are summarized in the next page.

Commercial respondents were recruited from Terasen's customer database. These respondents were first approached by phone. Once their participation was secured, they were asked for their email addresses, so that the survey link could be sent to them. The survey had to be conducted online because the DCM analysis contained in this research project requires an online interface with respondents.

Appendix To The Methodology (cont'd)

Outcomes Of The Fieldwork: Residential Survey

	Number	Percent
Number of survey invitations sent	(9,963) #	(100) %
Completed survey	1,401	14%
Disqualified: Did not know if they are a Terasen customer	305	3%
Break off	205	2%
Quota fail	143	1%
Did not respond to survey	7,909	79%

Outcomes Of The Fieldwork: Commercial Survey

	Number	Percent
Number of telephone numbers dialed	(26,736) #	(100) %
Not In Service numbers	1,613	6%
Number of respondents who agreed to participate in the study	1,609	6%
Number of refusals	6,649	25%
All other call outcomes	16,865	63%
Number of online survey invitations sent	(1,606) #	(100) %
Completed survey	500	31%
Break off	158	10%
Did not respond to survey	946	59%

Appendix To The Methodology (cont'd)

Survey Margin of Error

Please note that margins of error apply to randomly selected samples. Residential panel samples are self selected and therefore the following margin of error figures are presented as a guide for readers. The overall sampling error for 1,401 total residential interviews at the 95% confidence level is approximately ± 2.6%. For example, if 50% of all residents surveyed stated that they have heard of carbon offsets, then we can be sure, nine times out of ten, that if the entire population had been interviewed, the proportion would lie between 47.8% and 52.2%.

When a segment of the entire data is analyzed, the sampling error increases. For example, the overall sampling error for data based on 200 interviews at the 95% confidence level is approximately ± 7.0%. In this case, using the scenario where respondents surveyed state that they would purchase a carbon offset, then we can be sure, nine times out of ten, that this proportion would lie between 43.0% and 57.0%.

The commercial survey results are subject to margins of error. At the 95% confidence level, the margin of error for the 500 commercial customers interviews is ± 4.4%.

A copy of the invitation and questionnaire used in this survey are appended to this report.

the sixth sense of business™

Overview: Terasen Residential Customer Satisfaction Research
February, 2011

Study Background & Methodology

In 2010, Terasen Gas adopted an additional customer satisfaction and commitment model. The new research focuses on continuous improvement. For the first time, benchmarks have been established to compare Terasen's customer satisfaction levels with those of other utilities. The results answered the following research questions:

- How satisfied are Residential customers with Terasen's services overall? And how does this level of satisfaction compare against other (1) natural gas companies, and (2) local utilities?
- How committed are customers to Terasen?
- How did Terasen perform on various aspects of its services?
- What can Terasen do to increase customer satisfaction?

Two waves of telephone interviewing were conducted in 2010 – one in the Spring and one in the Fall – interviewing a total of 1291 Residential customers for the year. In addition to interviews with Terasen Gas customers, results from a survey of 2,000 random Canadians are included in this study to compile benchmark information.

Highlights

- In 2010, Terasen moved to a new measure of satisfaction called the TRI*M score. It is an index composed of four questions about customer attitudes toward the organization. Unlike the Scorecard satisfaction scores, the TRI*M index is not a percentage. One important benefit of the TRI*M score is benchmarking and comparability, as seen below.
- Compared to other major natural gas utilities in Canada,[1] Terasen's satisfaction levels were around the market average. Union Gas emerged above their peers. Meanwhile, in BC, Terasen received similar satisfaction ratings as Shaw customers. It ranked behind BC Hydro and in front of Telus in a comparison of local utilities. Terasen's ratings on Vancouver Island continue to pull down the organization's satisfaction scores.

	ENBRIDGE	ATCO / DIRECT ENERGY	TERASEN GAS	MANITOBA HYDRO	SASK ENERGY	UNION GAS
Satisfaction Levels (TRI*M Score) Natural gas average = 54	47	47	55	62	65	67
Base:	n=180	n=115	n=1291	n=33	n=47	n=129

[1] It should be noted that scores derived from "actual" bases of less than 50 should be interpreted with extreme caution

	TELUS	SHAW	TERASEN GAS	BC HYDRO
Satisfaction Levels (TRI*M Score) BC utilities average = 52	39	54	55	63
Base:	n=207	n=191	n=1291	n=230

- Approximately half of Terasen Residential customers (49%) are committed to the organization. Committed customers are loyal to Terasen and will not switch to an alternative fuel source.

- Strengths: Customers who have dealt with a Terasen technician or crew say that these services are the strength of the organization. For the broader base of residential customers, they feel that Terasen is a reliable company with a concern for public safety first.

- Opportunities for Improvement: Rates and corporate communications are two of the main areas of improvement for residential customers. With respect to communications, customers scored the organization lower on community involvement, and access to information on rebates and obtaining rebates. In addition, Terasen was not rated very high on being innovative or on helping to develop alternative energies.

- Key Drivers: Not every strength and area of improvement mentioned previously is a key driver of customer satisfaction. Prominent key drivers were calculated statistically. The areas Terasen Gas should focus on to increase customer satisfaction for Residential customers include:

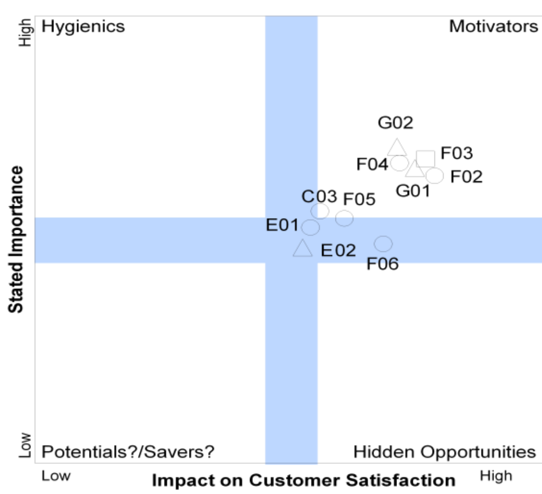
  - Communicate competitiveness of rates compared to alternatives;
  - Corporate communications that are easy to understand;
  - Corporate image, including:
    - Demonstrating commitment to customers;
    - Terasen's reliability, trustworthiness and respectability;
    - Terasen's ability to anticipate the needs of communities and customers;
  - And rebate incentives for energy efficiency upgrades.

Rates
G01 COMPETITIVE RATES COMPARED TO ALTERNATIVES
G02 WORKS HARD TO OBTAIN BEST POSSIBLE PRICING

Communications
C03 HAS COMMUNICATIONS EASY TO UNDERSTAND
E01 INFORMATION HELPS CUSTOMERS USE NATURAL GAS EFFICIENTLY

Corporate Image
E02 OFFER REBATES FOR ENERGY EFFICIENCY UPGRADES
F02 IS COMMITTED TO HELPING ITS CUSTOMERS
F03 IS RELIABLE COMPANY
F04 IS TRUSTWORTHY COMPANY
F05 ANTICIPATES IMMEDIATE/LONG-TERM NEEDS OF CUSTOMERS/COMMUNITIES
F06 IS A RESPECTED COMPANY

Performance
Far above average
Above average
Average
Below average
Far below average



Opportunities

There are three opportunities that we recommend Terasen Gas prioritize when outlining objectives in the next year:

1. ***Improve perceptions of Terasen's rates.*** Customers will always be unhappy with the rates they pay; however, at this point in time, the dissatisfaction is strong enough that it is a central issue in the minds of Residential customers. In light of depressed commodity prices, TNS recommends contrasting price advantage compared to alternative thermal energy products.

2. ***Communicate that Terasen is committed to helping customers.*** This could include making it easier for customers to get efficiency rebates and to get more information about rebates. It could also involve being more active or visible in communities. Residential customers indicate that Terasen Gas should be seen to be doing more to help customers.

3. ***Improve the clarity of communications to customers.*** Consider testing future communications and ads prior to finalizing to ensure that specific communication objectives are achieved.

<u>Appendix D</u>

Biomethane

1. 2008 Long Term Resource Plan Excerpts
2. 2010 Long Term Resource Plan Excerpts
3. Biomethane Application Excerpts
4. Biomethane Application IR Excerpts
5. 2010-2011 TGI RRA IR Excerpts
6. FEI Tariff General Terms & Conditions – Section 28

Project Benefits

The electricity generated is a clean energy since it is captured from waste heat with no additional use of fuel. Since the electricity produced at the site can be delivered to the grid through existing distribution lines that currently service the facility, new transmission lines can be avoided. Other environmental impacts such as noise, line of sight, and water quality issues are avoided as the project will be developed within an existing facility. The project will provide an overall balance of energy efficiency, environment & economy.

This potential project is expected to generate about 3.2 MW of electrical power capacity and approximately 15,000 to 18,700 MWh per year of clean energy – enough to meet the electrical demand for 1,500 to 1,800 homes in the Lower Mainland. At this level of power generation, the project will qualify for sales to BC Hydro under the Standing Offer Program. Income from electricity sales would offset the project costs to the benefit of TGVI ratepayers.

A number of other benefits for TGVI and the province can be realized. The project will:

- help meet the BC Energy Plan objectives of self sufficiency and net zero GHG emissions;
- displace over 13,510 tonnes[33] CO2e of GHG emissions per annum compared to imported electricity;
- optimize the energy used to deliver natural gas to TGVI and improving overall energy efficiency in the province;
- provide electricity in close proximity to B.C.'s largest load centre with a peak seasonal generation profile that matches the needs of BC Hydro's winter peak demand; and
- use known engineering principles and proven technologies to ensure project success.

Terasen Gas will continue to examine the technical and economic requirements of this project as well as sources of potential funding to assist with its implementation. Discussions with BC Hydro are underway to ensure the project can meet the specifications of the Standing Offer Program, and appropriate applications will be brought forward as the project's technical and economic feasibility become certain.

7.2.2 Biogas Upgrading

Another opportunity that Terasen Gas is investigating to reduce carbon emissions, increase energy efficiency and optimize existing energy infrastructure is the potential for new, green sources of natural gas. Biogas – methane produced through the processing of animal and other organic wastes – has potential to be brought into the Terasen Gas pipeline system, mixed with other more traditional supplies of natural gas and sold to customers as a more sustainable, lower impact alternative. Biogas can be combined with traditional natural gas supplies to create cleaner and lower GHG intensive energy alternatives.

[33] Based on GHG emission factor of 855 tonne CO2e/GWh for a 560 MW greenfield thermal coal plant at the Hat Creek site, as stated in BC Hydro 2006 IEP, Appendix F, 2005 Resource Options Report

Biogas is primarily manufactured through the process of anaerobic digestion of plant and animal waste. At this time, Terasen Gas has identified three alternative sources of potential biogas resources in B.C. that it might be able to access: methane produced by anaerobic digestion from agricultural waste and / or crop and animal processing industries, methane produced as a natural by-product in municipal sewage treatment systems and methane produced within solid waste landfill sites as waste materials break down beneath the soil.

7.2.2.1 Agricultural Biogas

British Columbia's agricultural system appears to be sufficiently large enough to develop opportunities for biogas production and upgrading. Terasen Gas is currently in the early stages of gathering information and talking with industry experts to help understand the magnitude and challenges of the biogas opportunity.

A recent study commissioned by the B.C. BioProducts Association identified 2,500 terajoules annually of economically viable biogas produced from agricultural waste available in the Fraser Valley region of British Columbia. This represents enough energy to displace the annual natural gas usage in 25,000 B.C. homes.

7.2.2.2 Methane Produced at Municipal Wastewater Treatment Plants

Biogas is also produced through anaerobic digestion as part of the treatment process at many municipal wastewater treatment plants. As such these plants are potential suppliers of biogas. Similar to biogas produced from agricultural waste, the biogas from wastewater treatment plants would require upgrading to meet pipeline quality standards.

Although the total potential biogas available from sewage treatment plants in B.C. has not yet been quantified, Metro Vancouver has determined that its sewage treatment plants alone have the potential to produce 740,000 GJ of pipeline quality carbon neutral gas or enough gas to heat 7,400 homes. Terasen Gas is currently working with Metro Vancouver on a potential demonstration project at the Lions Gate Treatment Plant to demonstrate the viability of upgrading biogas to pipeline quality gas that can be injected into the Terasen Gas system. The Company also continues to evaluate other biogas potential across B.C.

7.2.2.3 Landfill Gas

The B.C. Bioenergy Strategy released by the provincial government in February 2008 indicated that the government will develop legislation to phase in requirements for methane capture at landfills, the source of about nine per cent of B.C.'s greenhouse gas emissions. This methane could be used for clean energy. With the requirement to capture the methane produced at landfill sites there is an opportunity to upgrade the landfill gas to pipeline quality and inject it into the gas delivery infrastructure. Terasen Gas will continue to assess the feasibility of incorporating landfill gas production areas from across the Province into B.C.'s natural gas supply.

Developing Biogas Supply

Terasen Gas has applied for funding under the Innovative Clean Energy (ICE) Fund to develop a biogas upgrading demonstration project at Metro Vancouver's Lions Gate Waste Water Treatment Plant.

The project would provide enough carbon neutral gas to displace the natural gas usage of over 100 homes and CO2e reduction equivalent to removing 165 passenger vehicles from the road.

7.2.2.4 Developing Biogas as an Alternative Supply

One of the primary concerns for gas utilities interested in the potential of biogas is the quality and heat content of the gas produced. Terasen Gas is working with the agricultural and municipal waste sectors, as well as biogas upgrading equipment manufacturers to develop a biogas upgrading project in which the lessons learned could be used to develop future large scale projects. Such projects could help reduce the greenhouse gas emissions by capturing the methane, upgrading it and using the upgraded product as an energy source rather than being flared or vented into the atmosphere.

Terasen Gas is also evaluating various options as to how biogas will be incorporated into its supply portfolio. Current options under investigation include, using the carbon neutral gas to offset greenhouse gas emissions from compressor and other operating equipment, provide customers an opportunity to pay a premium to purchase biogas as an alternative fuel source, or incorporate the biogas into the core gas supply portfolio. Terasen Gas' objectives are to continue evaluating the biogas potential and if feasible, to help develop this new potential industry sector to allow for biogas sales, offering customers as a more sustainable augmentation to natural gas supply that will allow for a reduction in the overall carbon footprint.

7.3 Alternative Energy Systems

Alternative energy systems for space and water heating have been discussed in Chapter 2 and Appendix D in relation to the competitive position of natural gas. However, natural gas can also be an important component of these types of systems in serving both individual homes and neighbourhoods through district energy systems. Development of these technologies can also lead to the growth of distributed electricity generation facilities and technologies, which can help to meet Provincial objectives for electricity sustainability and the development of new clean and efficient sources of supply.

improving the utilization of the existing natural gas infrastructure. The Utilities expect to grow demand in its NGV target market to 30 PJ annually by 2030. NGV solutions must be complete solutions, however, and provide the customer with service that allows them to directly fuel their vehicles and equipment without the need for them to supplement a portion of the service, or risk the unwillingness to participate in this important opportunity.

TGI intends to bring forward an application to the Commission in the summer of 2010 for approval of more complete transportation fuel service offerings. That application will include the requirement for and appropriate treatment of CNG and LNG fueling infrastructure being sought from the Utilities by existing and potential future customers. Extension of a more complete NGV service to the TGVI and TGW service territories is contemplated at a later date pending future unbundling of gas delivery rates for these utilities.

More Opportunities for Compressed Natural Gas:
Napa Valley Wine Train Example

The Napa Valley Wine Train started a program for the experimental conversion of a Napa Valley Wine Train Alco locomotive to 60% natural gas and 40% diesel fuel mixture. In 1999 the conversion became permanent. A total conversion of locomotive 73 was completed and it was put into service using 100% Compressed Natural Gas on in 2008.

Source: http://winetrain.com/about/our-train

3.1.6 CARBON NEUTRAL BIOMETHANE OFFERING

Biogas is a readily available supply of renewable gas from landfills, sewage treatment plants, food waste, and agricultural operations. Established technology exists that can be used to upgrade biogas to biomethane, which has characteristics that make biomethane a reliable and safe substitute for natural gas. Moreover, biomethane is a renewable fuel. The production and consumption of biomethane is considered carbon neutral. The use of this carbon neutral fuel in place of a carbon positive fuel such as natural gas results in a net reduction of GHG emissions as well as other environmental and economic benefits for potential biogas producers throughout the province. This offering to customers promotes government's energy policy objectives favoring the use of renewable energy, the efficient use of energy and reducing GHG emissions. More importantly this product offering and business model meets the needs of our customers. TGI's biogas initiative also helps create green jobs and industry within B.C. and can help improve the sustainability of waste management practices in many of the provinces regions and industries.

In its 2008 Resource Plan, Terasen Utilities identified the development of biogas supply and sales as an important initiative and action plan item. Today, two separate supply projects are under way, and a TGI application to the BCUC for approval of a comprehensive, flexible, end to end biogas supply and sales tariff program is now in a regulatory review process[78]. TGI intends to continue developing biogas supply resources and extending its green gas offering to more customers as supply and demand growth allows.

Market research completed in 2010 suggests that our customers have a strong desire to purchase renewable clean energy from the Utilities. TGI's biogas projects and low carbon fuel (or "Green Gas) offering is a way to align our service offerings in order to fulfill our customers' desire to be part of the solution in meeting changing environmental issues. The data collected by the Utilities shows that large numbers of residential and commercial customers want to use biomethane, far more customers than TGI believes it can serve during the initial stages of its biogas initiative. The development of biogas supply and a Green Gas offering to customers will help us meet the demands and expectations of customers.

The development of renewable energy is more advanced in the electricity industry in B.C. than it is in the natural gas industry, in terms of both the quantity of supply developed and the business models and contractual arrangements supporting the industry. The heavy policy focus in B.C. on developing renewable electricity resources combined with the existing extensive hydro-based Heritage electricity resources create the public impression that B.C. electricity is the only "green" and environmentally-preferred energy source. In these circumstances it is becoming more difficult for natural gas to compete on an environmental basis.

In response, TGI plans a measured, phased, flexible and scalable that balances supply and demand for biomethane through a Green Gas offering. TGI believes that offering a renewable energy product will help meet customer demand for environmentally friendly options. Further, it will help to establish a path forward for complying with any future mandatory requirements for including renewables in a utility's energy mix, if and when renewable portfolio standard or similar regulation may be established for natural gas utilities in B.C..

[78] TGI's 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 was submitted to the BCUC on June 8th, 2010.

3.1.6.1 Three Types of Voluntary Green Pricing Programs

The term "green pricing" is used in reference to utility programs in which utility customers pay a premium to have a portion of their energy come from a renewable energy source. Utilities use these funds to invest in renewable energy development or purchase carbon offsets on behalf of their customers to offset GHG emissions associated with their energy use. In recent years, a number of different models have been developed by public utilities in Canada and the U.S. to deliver green products and pricing to customers. In this section, TGI provides an overview of the types of voluntary[79] green business models or programs that have been employed in North America, discusses participation rates in North American voluntary programs based on certain green pricing premiums, and reviews a few specific examples of green pricing programs in North America. This discussion provides the context and background for the Utilities' proposed demand-side business model discussed later in this section.

There are three main types of programs that are being offered in the voluntary renewable energy market: contribution programs, energy-based programs, and offset programs.

- **Contribution Programs:** The earliest types of programs were contribution programs that were designed to allow customers to contribute to a utility managed fund for renewable energy project development. In most contribution programs, customers can determine the amount of their monthly donation. In some cases the customer contribution is tax deductible, which utilities accomplish by setting up separate non-profit entities to administer the program.

- **Energy-based Programs:** The second and most successful are the energy-based programs. This type of program allows customers to choose a selected amount of energy to be supplied from renewable sources for a premium. Typically green pricing programs are structured so that customers can either purchase green power for a certain percentage of their energy use (often called "percent-of-use products") or in discrete amounts or blocks at a fixed price ("block products"), such as a 100 kWh block of electricity.

- **Carbon Offset Programs:** The third and newest type of offering is a carbon offset program. This type of program offers customers the option to offset their GHG emissions for the energy use in their homes or business. The utility either acquires carbon offsets from their own projects or contracts with a third party to acquire carbon offsets on their behalf. Most utilities have criteria around which types offsets will be purchased, such as

[79] Green pricing programs generally fall under one of two general headings: voluntary programs and forced renewable portfolio programs. In general terms, voluntary programs are green pricing offerings that customers can elect to participate in, usually for a premium that is added to their bill. In contrast, forced renewable portfolio programs are programs that utilities are required to implement pursuant to legislation, which typically requires the utility to include a certain percentage of renewable energy within their power generation mix (such as BC Hydro). Terasen Gas focuses on a discussion of voluntary programs, as Terasen Gas is not currently being made to pursue a forced renewable portfolio program.

Biogas projects, wind projects, and/or solar projects within their jurisdiction or service territory.

Utility green pricing programs in the U.S. have grown significantly over the past decade. A 2007 Chartwell report indicated that 58% of utilities surveyed had some kind of green pricing program[80]. The National Renewable Energy Laboratory (NREL) reports that more than 850 utilities in the U.S. have some sort of green pricing program[81]. The vast majority of programs offered are for renewable electricity programs, however, gas utilities are now entering the arena as a way to respond to consumer demand to reduce their carbon footprint. TGI has concluded that, among the three voluntary green pricing models in use in North America, and supported by the primary research (see following section), a renewable energy-based program is appropriate for its customers at this time.

3.1.6.2 Demand in B.C.

TGI commissioned TNS Canadian Facts[82], one of Canada's largest marketing and social research firms, to conduct a primary market research study to validate and evaluate the potential customer demand for a biogas program in B.C., its market drivers, and factors affecting different price points. Two comprehensive studies (herein after referred to collectively as the "Study") were conducted (between November 2009 and January 2010) of B.C. households and businesses to understand consumer demand specific to biogas and aid in the development of a Green Gas program. Detailed findings of the Study can be found in Appendix B-9 (Biogas Market Summary Report). A summary of the results of this Study that assisted TGI in coming to the following determinations on the framework for a Green Gas offering are discussed below.

3.1.6.2.1 Demand in B.C. Terasen Utilities' Conclusions Regarding Program Design

This market research suggests that a majority of customers support TGI's involvement in developing Biogas supply resources and providing a renewable product offering. TGI considers that the results confirm the direction it is taking in developing Biogas supply and a Green Gas offering. TGI considered the results of the Study in structuring its Green Gas offering. In particular, the Study results suggested:

> *"TGI should develop a renewable energy-based (Biogas) program and tariff offering whereby customers can sign up for a portion of their natural gas to come from Biogas. This type of program is preferred to offsets."*

---

80 Chartwell, Helping Customers Live a Sustainable Lifestyle, May 2007
81 NREL, Green Power: Marketing in the United States: A Status Report (2008 Data)
82 TNS Canadian Facts is one of Canada's largest marketing and social research firms. TNS was established as Canadian Facts in 1932 as the country's first survey research organization. Today, they have offices in Toronto, Montreal, Ottawa and Vancouver, with 170 full-time members of staff.

Customers perceive value for all gas customers from TGI's development of the Green Gas offering; therefore, a cost treatment that involves some costs associated with offering the renewable energy-based program being borne by all customers is appropriate.

Targeting residential customers in the initial rollout is reasonable, since residential customers indicate a higher participation potential (16% vs 10% for commercial) and have greater certainty around use rates in order to better manage supply and demand imbalances. TGI proposes to expand the Green Gas offering to the commercial market once Biogas supply is further established and experience has been gained with the program in the residential market.

The initial offering will be for a 10% blend of Biogas as there is a larger preference for a 10% price premium at a 10% GHG reduction level relative to the 20% price premium / 20% GHG reduction or 30% price premium / 30% GHG reduction alternatives. The 10% blend will also allow TGI to maximize household involvement by reaching more customers with the available supply of Biogas relative to the other two options studied.

The offering may also be expanded to include additional blends of Biogas and to reach additional niche markets once Biogas supply is further established.

In summary, TGI believes that the market research that has been done demonstrates that customers are very supportive of Terasen Utilities developing biogas supply resources and providing a renewable product offering.

3.1.6.3 Key Elements of Proposed Green Gas Business Model

TGI proposes to phase-in the implementation of the Green Gas program over a multi-year period to ensure that the Green Gas product offering is effectively positioned for customer participation and to match the supply that is available.

- TGI proposes creating a new Biomethane Tariff, similar to TGI's Standard Rate, to allow eligible customers to either remain on the standard commodity rate or to select the TGI's Biomethane Tariff which will be a specific blend of biomethane and conventional natural gas (for Phase 1, TGI proposes a blend of 10% Biomethane and 90% conventional natural gas).

- Gas Marketer rules and functionality that are part of the Customer Choice program will remain unchanged as the customer will continue to have choice of commodity supplier between a Gas Marketer's fixed rate and the TGI variable rate.

- The number of customers eligible to participate in the Customer Choice program will not be impacted and the Gas Marketer base load requirements will be calculated based on the same methodology that exists today. This methodology is defined as the Monthly Supply Requirement or MSR.

- By electing to remain with TGI as the commodity supplier, a customer may choose to remain either on the standard rate (e.g., TGI Standard Rate Schedule 1) or they may select the Biomethane option (TGI Rate Schedule 1B), which is understood to be a specific blend of Biomethane (eg. 10% Biomethane; 90% conventional natural gas).

- Biomethane rates will typically be set on a forecasted 12 month period and the non-biomethane commodity tariff rate will remain subject to quarterly rate adjustments. The Biomethane Residential Tariff, will be an open tariff like the TGI Standard Rate Schedule 1[83]

- TGI proposes to phase-in the implementation of the Green Gas program over a multi-year period in order to confirm market interest, demonstrate the ability of producers to deliver a reliable supply of Biomethane, and to verify that processes supporting the business model function effectively, while ensuring costs of supply are recovered by customers who opt into the program. The phased rollout is described below.

3.1.6.3.1 Phased Product Offering Strategy

The sales model TGI proposes to use for the Green Gas program is designed to be sufficiently flexible to enable a phased introduction of the Biomethane tariff option that allows for expansion of the product offering as additional supply becomes available. Two phases are planned:

Phase 1 is expected to launch in Fall 2010, and is generally targeted at residential customers. The objectives of the initial roll-out of the Green Gas program will be to validate producer reliability and consumer interest. These objectives will be carried out by a flexible, simple, cost effective business model solution. The objective of market validation is addressed in Phase 1 by targeting the Green Gas offering at residential customers. TGI's research shows the highest uptake potential in the residential market; therefore, this sales model will allow for the maximum participation in a Green Gas offering while minimizing billing system impacts in the near term with one tariff. Leading with a single product (a 10% blend) will allow for tighter control over the number of enrolments and will match the limited supply in the first year. Actual residential customer use rates have a tighter range around an average than commercial customers, which will help to predict total consumption for residential customers who enrol in the program.

Phase 2 is currently anticipated to begin in the first quarter of 2012, will expand the product offering to match demand once supply has been further established and the Utilities new Customer Information System ("CIS") is in place so as to minimize unnecessary incremental costs associated with an additional tariff offering. This phase is foreseen to be launched around the first quarter of 2012. This phase will see the roll-out of a Commercial Green Gas offering to Rates 2 and 3 (called 2B and 3B), as well as higher blends from the currently

[83] The Company's research of other green pricing programs elsewhere in North America found that the majority of green pricing programs offered by utilities have open entry and exit dates for residential customers. Source: NREL, Green Power: Marketing in the United States: A Status Report (2008 Data)

proposed 10%. There is also some support for higher-percentage blends and offerings to small commercial customers as demonstrated in the supporting documentation. In addition, larger commercial customers and industrial customers have informally voiced interest in being included in a future expanded Green Gas program.

Phase Two could also allow an expansion of eligible customers to include other regions such as Vancouver Island, the Sunshine Coast, Powell River, and Whistler. Further expansion to customers within Rate Schedules 4 to 7 is envisioned for 2013. All expansion of the Green Gas offering would be conditional on consumer interest and the availability of sufficient supply.

The expected rollout to other regions and rate classes will be driven by uptake rates in the first phase of the program, as well as supply availability, and could be modified from time to time. The benefit of this sales model is that it will support additional rate offerings with little or no system impact starting 2012.

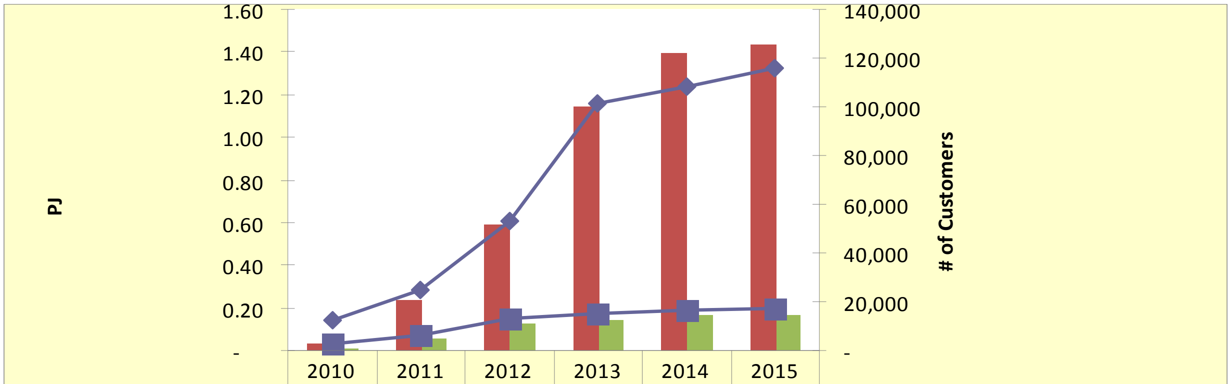
3.1.6.4 Projected Demand

While TGI's primary research indicates that there is a potential market for 16% of residential customers to sign up for a renewable energy-based program, TGI is mindful that other green pricing programs on average do not experience this type of participation rate. For the purposes of developing the program rollout strategy, TGI has analyzed two scenarios:

- Ramping up to the industry average participation rate of 2.2%[84]; and
- Ramping up to the potential market share identified in the primary research Study of 16% for residential customers and 10% for commercial customers.

[84] NREL, Green Power: Marketing in the United States: A Status Report (2008 Data)

Figure 3-6: Low and High Demand Scenario



	2010	2011	2012	2013	2014	2015
High Volume (PJ)	0.03	0.23	0.59	1.14	1.39	1.43
Low Volume (PJ)	0.01	0.06	0.13	0.14	0.16	0.16
High # of customers	12,340	24,679	53,061	101,159	108,416	115,662
Low # of customers	3,085	6,170	13,158	14,881	16,844	17,118

The low demand volume projections for the residential market match up quite well with the two near term supply projects included in the Biomethane Application. The commercial volumes however do not appear reflective of the anticipated volumes that would be associated with their participation. Forecasting the commercial volumes using the average number of participants as other green pricing programs does not seem to account for volumes from customers that may have multiple premises for which they want to purchase biomethane. Non-residential participants of other green pricing programs across the U.S. represent 70% of the volume in green pricing programs. Using the number of program participants in the low demand scenario reflects only 7% of the program volume from commercial and the high demand scenario 36% of the biomethane volumes. Therefore, estimating demand in the commercial sector is much more difficult. The commercial market rollout will have to be monitored closely to account for the wide range of demand scenarios. TGI anticipates that the associated volumes from the commercial market will likely be much closer to the high demand scenario.

3.1.6.5 Low Carbon Fuel ("Green Gas") Conclusions and Recommendations

Biogas is a renewable energy source that can be upgraded to carbon neutral Biomethane. When Biomethane is injected into Terasen Utilities distribution system it offsets the use of natural gas and reduces GHG emissions. Terasen Utilities, as the major natural gas utility in British Columbia, is uniquely positioned to promote the development of Biogas upgrading in B.C. The proposed Green Gas Offering allows for a phased approach to gauge consumer demand and drive supply project initiatives that can be expanded to customer groups as supply builds. Success of the program will be monitored closely and development of additional blends and expansion to other service territories could unfold over time.

In Summary, the Green Gas offering represents a significant first step in the development of Biogas as a new source of renewable energy to meet TGI's customers' needs. This offering to customers promotes government's energy policy objectives favoring the use of renewable energy, the efficient use of energy and reducing GHG emissions. TGI has a role to play in helping develop this industry that otherwise might not develop without utility support.

3.1.7 OTHER LOW CARBON AND RENEWABLE ENERGY SOLUTIONS

The Terasen Utilities will continue to explore new technologies and test their appropriateness for inclusion as part of our low carbon initiatives. Combined heat and power, generating electricity from waste heat at our compressor stations, advanced metering and other emerging technologies continue to show promise for potential future applications within the Utilities' integrated, low and no carbon portfolio of energy solutions. Customers are looking for Terasen Utilities to provide these solutions as we transform into a complete, integrated energy provider.

Some technologies may also prove to be disruptive, rather than complimentary to the Utilities core natural gas service offerings. The Utilities research and investigations will seek to uncover these challenges as well as market opportunities to add to and improve on the secure, reliable and cost effective energy services we provide.

2 BIOGAS AND BIOMETHANE

2.1 Introduction

Biogas is a readily available supply of renewable gas from landfills, sewage treatment plants, food waste, and agricultural operations. Established technology exists that can be used to upgrade Biogas to Biomethane, which has characteristics that make Biomethane a reliable and safe substitute for natural gas. Moreover, Biomethane is a renewable fuel. The production and consumption of Biomethane is considered carbon neutral. The use of this carbon neutral fuel in place of a carbon positive fuel such as natural gas results in a net reduction of GHG emissions.

In this section, Terasen Gas provides an introduction to Biogas, including describing:

- Why Terasen Gas must invest in equipment to upgrade Biogas to Biomethane;
- What is meant by the terms “Biogas” and “Biomethane”;
- The sources of Biogas;
- How Biogas is upgraded;
- The interchangability of Biomethane with natural gas; and
- Biomethane as a renewable fuel, the use of which can reduce GHG emissions.

2.2 Why Terasen Gas Must Invest in Biomethane Upgrading

As will be demonstrated in Section 3 of this Application, Terasen Gas customers want to purchase and consume Biomethane. Terasen Gas is submitting this Application to ensure that this demand is met safely, reliably and economically. Owning and operating the required upgrading facilities promotes the efficient development of Biomethane supply projects to meet customer demand. It ensures that the Biomethane that is injected into our distribution system arrives safely and economically, and also that the flow is reliable and dependable for customers. The Company is also actively pursuing independent partners who might be entrusted with the task of acquiring Biogas and upgrading it to pipeline-quality Biomethane which Terasen Gas can then purchase, inspect, and inject into our distribution system provided they can meet the safety and reliability standards required for our customers.

It is important to note, however, that Terasen Gas is not proposing to invest in Biogas collection assets. As will be discussed further in Section 8, these assets make up the majority of the capital investment in a Biomethane project, but are currently outside the area of expertise of the Company and as such we are proposing that those assets will, in all cases, be owned and operated by a project partner.

2.3 Definition of Biogas and Biomethane

Terasen Gas uses the term "Biogas" in this Application to refer to a gas substantially composed of methane that is produced by the breakdown of organic matter (biomass) in the absence of oxygen. This breakdown process is also known as anaerobic decomposition. One of the primary products of anaerobic decomposition is gaseous methane, which is also the primary component of natural gas. [4]

Biogas is comprised primarily of methane (CH_4) and carbon dioxide (CO_2) with much smaller amounts of contaminants such as hydrogen sulphide (H_2S) and ammonia (NH_3). Trace amounts of hydrogen (H_2), nitrogen (N_2) and oxygen (O_2) are also occasionally present in Biogas. Usually, the gas is saturated with water vapour and may contain dust particles and organic silicon compounds (siloxanes).

Biogas, in its raw form, can be combusted; however, it does not produce as much heat as natural gas because of the relatively low amount of methane. Moreover, other contaminants may create problems such as corrosion or equipment fouling when put to uses other than simple flaring. In comparison, natural gas found in British Columbia homes and businesses has been refined to remove such impurities and contains almost 100% methane along with a small amount of other combustible gases such as ethane. In order to remove unwanted gases from Biogas, it is processed in a similar fashion to raw natural gas. The primary processing is the removal of non-combustible gas which will increase the heating value of the gas. Elements such as N_2, O_2 and H_2 are monitored to ensure that, if they are present, they are present in such small amounts that they not impact the safety or heating value of the gas. Other contaminants such as H_2S, NH_3, siloxanes and dust are filtered out to ensure that the end product is clean and safe for pipeline injection. For the purpose of this Application, the purification process will be referred to as "upgrading". Once Biogas has been upgraded, it is safely interchangeable with natural gas in the existing distribution and transmission system.

Purified or upgraded Biogas can be referred to as "Biomethane", a renewable form of natural gas. Throughout this Application we will principally refer to this upgraded Biogas as Biomethane. The terms "Biogas" and "raw Biogas" will refer to the gas generated from natural processes which has not yet been upgraded to Biomethane.

The table below shows a high-level comparison of the major typical components of Biogas versus Biomethane. It illustrates the high methane (CH_4) content of purified and upgraded Biomethane.

[4] Gas can also be created from the process of biomass gasification. The gasification process is different than anaerobic decomposition and the resulting gas has a different composition. Gasification creates a gas that primarily consists of hydrogen, carbon monoxide and varying amounts of methane and is more appropriately called "syngas". For the purpose of this application, "Biogas" will refer only to gas that is the product of anaerobic decomposition and, therefore, composed primarily of methane and carbon dioxide.

Table 2-1: Comparison of Biogas and Biomethane

Raw Biogas	Biomethane
40% - 60% CH_4	>96% CH_4
30% - 50% CO_2	<2% CO_2
0% - 2% O_2	<0.4% O_2
0-2000+ ppm H_2S	Sulphur-free
ppm VOC's	VOC-free
H_2O Saturated	<65 mg/m^3 H_2O
Low Pressure	Distribution pressure (>400kPA and <700kPA)

For the purposes of this Application, the term "Green Gas" will be used to describe the specific product offering Terasen Gas is proposing to make available to its customers. The Green Gas offering involves the purchase of a notional Biomethane product because, as described in Section 2.6 below, the Biomethane injected into Terasen Gas' distribution system is physically co-mingled with natural gas.

2.4 Biogas Sources

Biogas is produced from a number of sources. The Biogas from all of these sources is capable of being upgraded to Biomethane as the gas characteristics are generally the same within each of these categories. Four typical sources of Biogas are discussed below[5].

- **On-Farm Digesters:** This term refers broadly to covered storage vessels or lagoons located on operating farms that are used to break down large amounts of organic waste in the absence of oxygen. The typical waste used in on-farm digesters is crop residue or manure generated on the farm. In some cases, the feedstock may be supplemented by industrial organic wastes.

- **Centralized Digesters:** Typically centralized digesters are located near waste sources (such as waste transfer stations, farms or food processing industry) and accept waste from multiple sources with the specific intent of converting that waste to energy. In addition to the centralization of waste that might otherwise be found in an On-Farm Digester, they might accept waste from bakeries, restaurants or food-processing facilities. The key distinguishing characteristic of this type of digester is the fact that organic wastes are collected in different locations and transported to a single location for the purpose of improved operational efficiency that is achieved with higher volumes.

[5] Technology around the world is currently being developed to use "Syngas" created from biomass gasification to create methane. The process to create Biomethane from Syngas is called methanation. For the purpose of this application, this may be considered as a source of Biogas in the future.

- **Municipal or Regional Landfills:** Typical landfills contain large amounts of organic waste from sources such as food, lawns, gardens and bio-degradable items such as paper products.

- **Municipal Sewage Treatment Digesters:** Most modern waste-water treatment plants are designed to separate liquid and solid waste. The solid waste remaining after liquid separation is digested on site in the same manner as an on-farm digester. Sewage treatment digesters differ in that the primary waste is derived from established municipal or regional sewage systems. Many wastewater treatment plants capture the raw Biogas and flare it on site to control odour.

The owners and operators (as well as operational procedures) for each of these general categories are typically similar within the categories. For example, municipal sewage treatment digesters are owned and operated by municipalities and run by operators who have similar skill sets and who follow similar operational procedures. Although the two sources of Biogas being proposed as a part of this Application are an on-farm digester[6] and a landfill, Terasen Gas may potentially obtain Biogas from any of the sources above.

2.5 Biogas Upgrading Processes and Technology

Biogas upgrading involves the removal of contaminants and CO_2, leaving behind the upgraded Biomethane that will be injected in to Terasen Gas' distribution system. In this section, Terasen Gas discusses the removal of contaminants, and the processes by which CO_2 can be removed efficiently and cost effectively.

The contaminants present in Biogas vary in regard to the effects on the system, but in most cases they create equipment issues such as corrosion or fouling of burners. From a safety perspective, contaminants may cause undesirable and potentially hazardous exhaust products. Contaminants are filtered at the source to ensure that they do not reach the pipeline and ultimately the customer. The contaminant removal is typically done using some form of redundant active filtration (such as active charcoal) as well as some kind of filter and/or cyclone process to ensure a reduction in the amount of particulate in the gas.

Once the contaminants are removed, the biggest single constituent in Biogas (other than methane) is CO_2. The presence of CO_2 in Biogas reduces its heating value and the required Wobbe Index[7] of the gas. Therefore, it is important to remove CO_2 efficiently and effectively to produce Biomethane.

6 A digester is a vessel for digesting especially plant or animal materials. Organic substances, e.g. animal waste, are decomposed in a controlled manner within a vessel so that the products of the decomposition can be processed further.

7 The Wobbe Index is an indicator of interchangeability of fuel gases. It is used to compare combustion energy output at an appliance. If two fuels have the same Wobbe Index, they will have the same energy output at an appliance and can therefore be considered interchangeable.

There are several different commercial methods for reducing CO_2. The most common methods are adsorption, absorption and membrane separation. The principle types of upgrading in use today are Pressure Swing Adsorption ("PSA"), Water Wash, Membrane Separation and Amine Wash. Terasen Gas performed a preliminary evaluation of the different options to help identify an efficient, cost-effective process that could be used for Biogas purification in British Columbia. By ensuring that a cost-effective purification system can be developed, Terasen Gas was able to gain confidence that a cost-effective supply project could be developed. This high-level evaluation was based on initial cost (assuming similar flow rates), operating costs, recovery[8] and purity[9]. The higher the methane content (on a percentage basis) the better the gas will match natural gas.

Two of the four technologies were ruled out after this initial review:

- The Amine Wash technology was examined but eliminated due to its relative high costs for smaller scale projects. It is not economical until Biogas flow is in the range of ten times the expected flows for the known projects in Terasen Gas' service territory. In addition, the use of Amines in the process adds to environmental contamination concerns that occur during operations and maintenance.
- The Membrane Separation technology was also examined and eliminated due to the fact that the purity of gas produced could not meet required pipeline quality specifications without additional gas processing. It has been used successfully in applications where a lower heating value is acceptable, such as direct use or applications where the gas is mixed in low amounts with natural gas.

The two remaining technologies mentioned – Water Wash and PSA – appear comparable in terms of cost, operating expenses, purification capability and purity of the final product based on the preliminary analysis. These two products have performance characteristics that are essentially equal based on the recovery and purity (within 2% of each other).

There are companies that specialize in particular methods of gas upgrading. Each of these companies has sufficient expertise to design a process that can remove all contaminants from Biogas and these companies typically offer a complete upgrading plant. The contaminant process may vary depending on the upgrading process because certain processes may remove more than one contaminant. In addition, site conditions, such as the presence of a specific contaminant may require some additional filtration or processing. Site-specific conditions would be considered on a case-by-case basis and the upgrading plant design could vary to account for the differences in the raw Biogas. To illustrate, the two upgrading processes that will be used for the pipeline injection projects are described below.

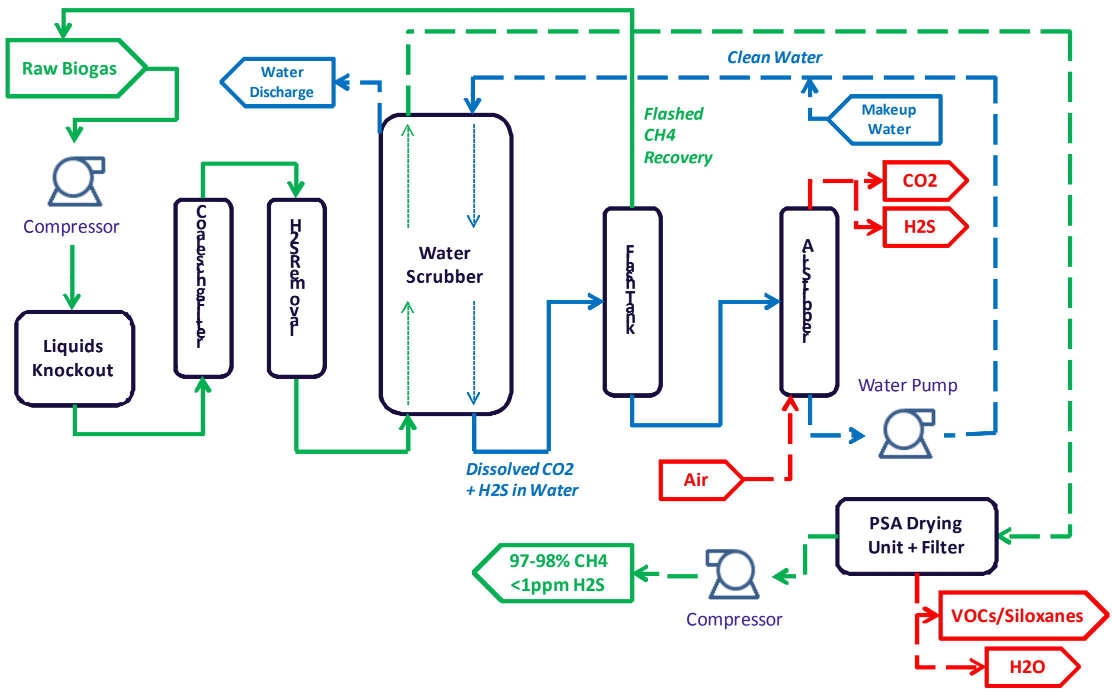
[8] Recovery can be best described as a measure of how much methane exits the process compared to how much methane is in the raw Biogas source.

[9] Purity is a measure of how well a technology can remove all non-desirable components from a gas, leaving only methane.

2.5.1 WATER WASH-BASED TECHNOLOGY

Water Wash scrubbing is a process that uses water as a solvent. As discussed above, the process must also account for other contaminants. A basic process is illustrated in the schematic diagram below (Figure 2-1) and described in the points that follow the diagram.

Figure 2-1: Water Wash Process Diagram



1) Raw Biogas is compressed, cooled and fed through a particle filter and an H_2S Removal vessel.
2) Biogas enters the scrubber to mix with pressurized water. CO_2 and H_2S are selectively absorbed.
3) Clean CH_4 passes through a final PSA drying unit and filter to remove moisture and exits the system.
4) CH_4 absorbed in used water is “flashed” off and recycled to the compressor inlet.
5) CO_2 is stripped from used water in Stripper Vessel and vented. Most of water is recycled.

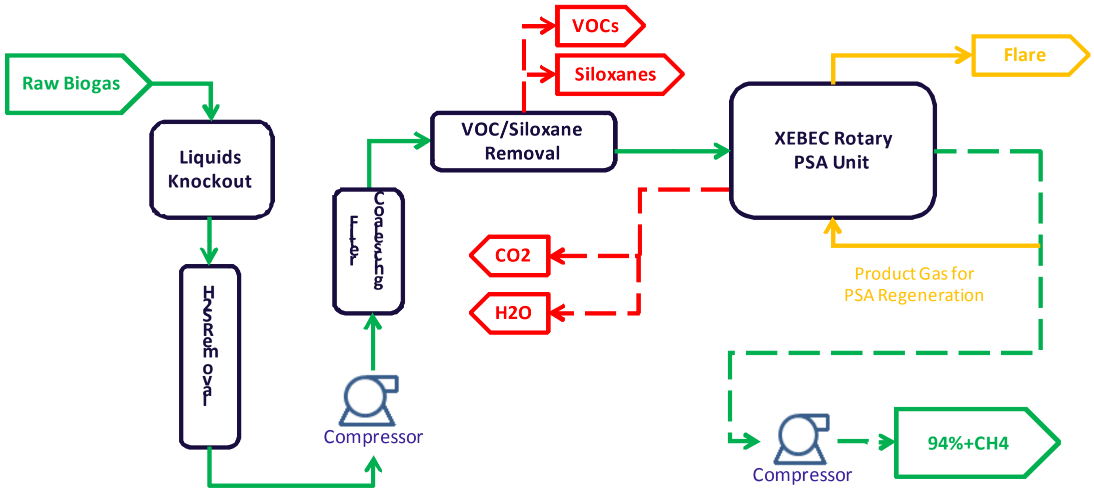
Water Wash systems have been successfully installed and operated for more than 20 years in locations around the world and there is a BC-based sales and service office for this technology (Figure 2-2).

Figure 2-2: Water Wash Biogas Plant, Courtesy of Greenlane Biogas

2.5.2 PSA-BASED TECHNOLOGY

PSA uses a material such as activated carbon in an adsorption process to capture CO_2 and remove it from Biogas (see Figure 2-3). Typically, contaminant removal occurs ahead of the PSA process to avoid contamination of the PSA vessels. The process involves rapid pressurization and de-pressurization of gas in a vessel to remove CO_2, hence the term 'pressure swing'. For successful pressure swing adsorption, the gas must first be dried and have the H_2S removed. Typically, multiple vessels are linked together and the process is repeated from vessel to vessel in a cyclical manner to allow for maximum gas throughput.

Figure 2-3: PSA Process Diagram



1) Raw Biogas is passed through a knockout drum to remove entrained moisture and through a H_2S removal unit.
2) Biogas is compressed to 800 – 1150kPa, cooled, and fed through a coalescing filter to remove oil from compressor and liquids.
3) VOCs and Siloxanes are removed in a desiccant vessel with reusable adsorbent media.
4) High Pressure Biogas enters the pressure swing adsorption vessel, where CO_2 is adsorbed by media while CH_4 passes through.
5) High purity CH_4 product gas is compressed and exits to pipeline.
6) PSA Vessel is regenerated by reducing the pressure in vessel and releasing the CO_2. A small amount of product gas is used to flush out the vessel. The exhaust is flared to remove trace CH_4 and contaminants before being vented.

One company, Xebec Inc, has developed a rotary PSA system that allows for a more rapid process with a smaller footprint (see Figure 2-4 below).

Figure 2-4: PSA System, Courtesy of Xebec Inc.

The application of established upgrading and filtering technologies provides a reliable means of refining raw Biogas supplies in British Columbia.

2.6 Biomethane and Natural Gas Interchangeability

Gaseous fuels are considered to be interchangeable when one gaseous fuel can be substituted for another in a combustion application without materially changing operational safety, efficiency and performance, and without materially increasing air pollutant emissions. Terasen Gas' commitment to customer safety and reliability of gas supply extends to ensuring that Biomethane injected into the Terasen Gas system is interchangeable with natural gas. The Biomethane mixed with natural gas in the system will meet the same quality standard as natural gas and it must perform comparably when injected into pipeline assets and consumed in end use equipment (including customer appliances). This interchangability forms the basis for notional delivery, which is an aspect of the proposed Green Gas offering.

2.6.1 ENSURING INTERCHANGEABILITY

Terasen Gas considers three key factors in confirming the interchangeability of Biomethane and natural gas: heat content, Wobbe Index and gas composition. Table 2-2 summarizes the criteria employed. Details about the three key factors are provided after the Table.

Table 2-2: Biomethane and Natural Gas Interchangeability Factors

Value	Criteria
Heating Value:	$36 MJ/m^3 – 41 MJ/m^3$
Wobbe Index:	$47.23 MJ/m^3 – 51.26 MJ/m^3$
Gas Composition:	
H_2S	$< 23 mg/m^3$
Total S	< 115 mg/m^3
CO_2	< 2 Vol. %
Water Vapour	< 65 mg/m^3
O_2	< 0.4 Vol. %
Total Inerts	< 4 Mol %
Butane Plus	< 1.5 Mol %

- **Heating Value**: The heating value is a measure of the amount of energy delivered per unit volume of gas. It is typically measured in Mega-Joules per cubic meter (MJ/m^3). The heating value for Biomethne will be determined primarily by the content of methane in the gas. A larger proportion of methane, compared to other non-heating gases such as CO_2, will provide more heat content for a given volume of gas.

- **Wobbe Index**: The Wobbe Index is defined as heating value divided by the square root of the specific gravity of a combustible gas. Because the Wobbe Index takes into account the specific gravity of a gas, it helps to provide a prediction of gas flow characteristics. Therefore, the Wobbe Index can be used as a measure to ensure that Biomethane will flow and burn in a similar manner to natural gas in appliances.

- **Gas Composition**: Gas composition is a means of quantifying the "recipe" of a given gas mixture. It takes into account all distinct gases that make up the total gas stream. By matching gas composition as closely as possible to natural gas, Terasen Gas will have confidence that Biomethane will not have any adverse effects such as corrosion on existing equipment or customer appliances.

In order to gain confidence about the interchangeability of Biomethane with natural gas, Terasen Gas participated with other partners in a scientific study of Biogas projects in other locations in North America. The study, entitled "Biogas to Biomethane, Upgrading for injection into the Natural Gas Distribution System" and found in Appendix A of this Application, showed that Biogas can be upgraded to meet safety and performance specifications equal to those of natural gas. In other words, Biomethane is interchangeable with natural gas.

2.6.2 NOTIONAL DELIVERY

The interchangeability of Biomethane with conventional natural gas allows for notional delivery using the existing natural gas distribution system. Biomethane can be injected at one point on the system, displacing conventional natural gas used at that point on the system. The user notices no difference between the gases, which allows the gas to be physically consumed in one place, but be accounted for as sold at another location through displacement.

Notional delivery is a concept that is employed in the trading of commodities. Another example that is in practice on the Terasen Gas distribution system involves gas from marketers in the Customer Choice program flowing to residential customers. If Customer A signs up with Marketer 1 and Customer B signs up with Marketer 2, both marketers are responsible for providing sufficient gas for their customers at the designated receipt points. In actual fact, Customer A may physically receive all, some or even none of the gas actually consumed at their home from Marketer 1 or 2. Neither Customer A nor B will ever know whose molecules they consumed because individual molecules of gas are not tracked. Instead, the system notionally delivers Marketer 1 gas to Customer A and Marketer 2 gas to Customer B, and charges each customer the appropriate rate for the gas they have notionally consumed. This Application proposes a similar notional delivery of Biomethane on the Terasen Gas distribution system.

2.7 Biomethane as a Renewable and Reduced Carbon Fuel

Biomethane is a renewable energy source. The production and consumption of Biomethane is carbon-neutral, and the use of Biomethane in place of a carbon positive energy source like natural gas results in a net reduction in GHG emissions. These three attributes of Biomethane are discussed below.

2.7.1 RENEWABLE ENERGY SOURCE

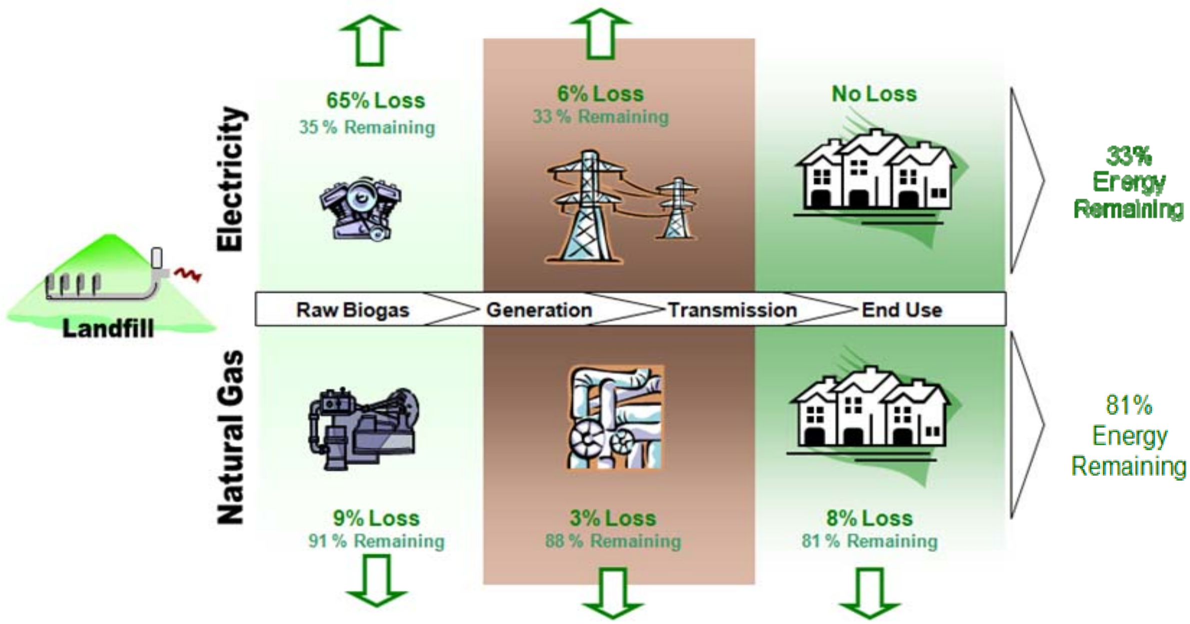
Biogas is a natural product that results from the breakdown of organic matter; therefore, it is considered to be a renewable source of energy. Biogas upgrading is an efficient use of this renewable energy source.

Biogas is the product of waste that would otherwise be lost to the atmosphere if left to dissipate. The origin of the gas is a direct result of the digestion of organic matter by bacteria in a low oxygen environment. All of this organic matter is grown ultimately from plants (whether subsequently fed to animals or not), which remove carbon dioxide from the atmosphere by photosynthesis. As more organic matter is grown, the source of Biogas is also replaced.

Upgrading Biogas to Biomethane for direct consumption in heating applications is the most efficient use of this renewable energy source. The process is between two and three times more efficient than converting raw Biogas into electrical energy for the same end use.

To illustrate, imagine a gas collection system at a landfill that will ultimately provide energy to a residence. The first step in the process (after collection) is to convert that raw energy into a transportable energy, i.e. Biomethane or electricity. The conversion process from Biogas to Biomethane is in the range of 90% efficient. In contrast, when converting to electricity using a reciprocating engine with no heat recovery the efficiency is closer to 35%. This means that before the energy is even transported, 65% of it has been lost. There are also losses in the transmission of energy – approximately 3% for gas and 6% for electricity. In the end use, homes are able to take advantage of all of the electrical energy for heating, whereas gas losses are typically 8% for a high efficiency furnace. Considering both the relative efficiencies of the conversion processes and the relative end use efficiencies, Biomethane is a more efficient use of the raw energy for the end-use of space heating (approximately 81% versus 33%). See below in Figure 2-5 for a graphical illustration.

Figure 2-5: Biomethane vs. Electricity – End Use Efficiency



As illustrated, when converting Biogas to electricity, for each unit of energy available from the resource, only about 33% of it actually does something useful in someone's home. Compared to approximately 81% in useful energy when converting to Biomethane, it makes sense to convert to Biomethane, when possible and economical, in order to make the most of the raw resource.

In certain cases, heat can be recovered from the electricity generation process. This could improve the amount of recovered energy and therefore the overall efficiency of the energy use. When heat recovery is used, the amount of energy that can be used varies depending on the proximity of an energy user – such as a building requiring heat. In the best cases, heat recovery can improve the overall efficiency to be comparable to the use of Biomethane (within a few percent). However, this option adds to the initial capital cost and it may not be realistic in many situations. For example, many landfills could be located away from any significant heat users or customers. Therefore, Terasen Gas believes that in many instances converting Biogas to Biomethane is the most efficient use of the waste resource.

2.7.2 CARBON NEUTRAL CONSUMPTION

The production and consumption of Biomethane is considered carbon (or GHG) neutral because producing and consuming Biomethane will not add to the amount of Carbon released into circulation.

GHGs are gases that once dissipated into the atmosphere, trap infrared radiation from the sun that has been reflected from the earth's surface. In effect, the gases act like a greenhouse –

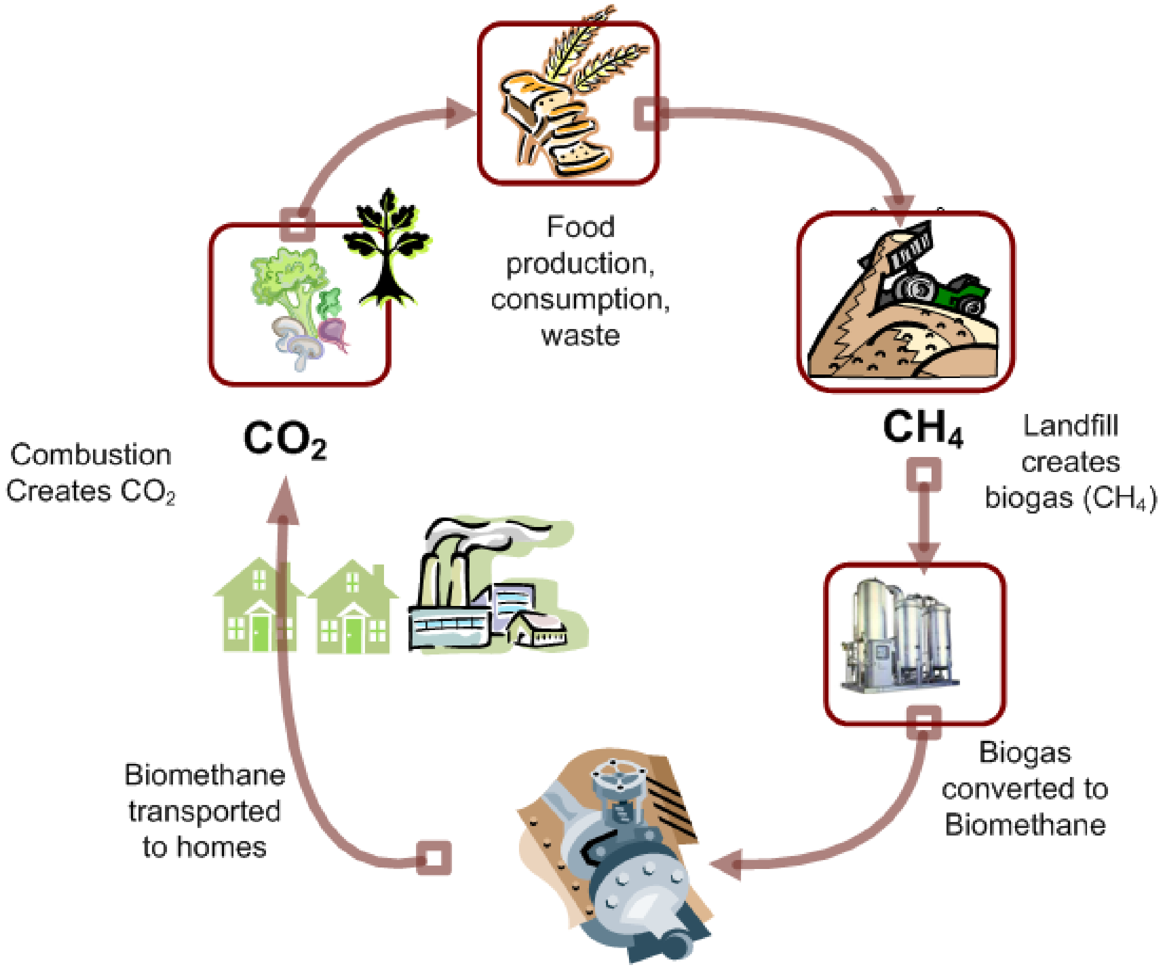
hence the name. Ultimately too much GHG emission will contribute to a warmer planet and climate change. For the purpose of this Application, the most relevant GHGs are carbon dioxide (CO_2) and methane (CH_4). More specifically, CO_2 and CH_4 that come from net carbon emitting sources – such as conventional natural gas wells - can contribute to an increase in GHG emissions. Methane will also be released as the result of the natural decomposition process of organic matter.

Food wasted in a landfill, for example, will produce methane, which must by law[10] be either burned or captured. Burning the methane converts it to carbon dioxide, which is then captured by plants. The plants are grown and harvested and the harvested grain is converted into some kind of food. The leftover waste from that food is then disposed of in a landfill, starting the cycle again. Capturing the Biomethane from the landfill and burning it in an end use application does not add any additional emissions than would otherwise be released through on-site flaring at the landfill.

Figure 2-6 below illustrates that Biomethane, as part of a closed-loop carbon cycle, is not a GHG and has a neutral effect on the greenhouse effect.

[10] For Landfill Regulation please refer to Appendix B-1

Figure 2-6: Carbon Cycle – Landfill example



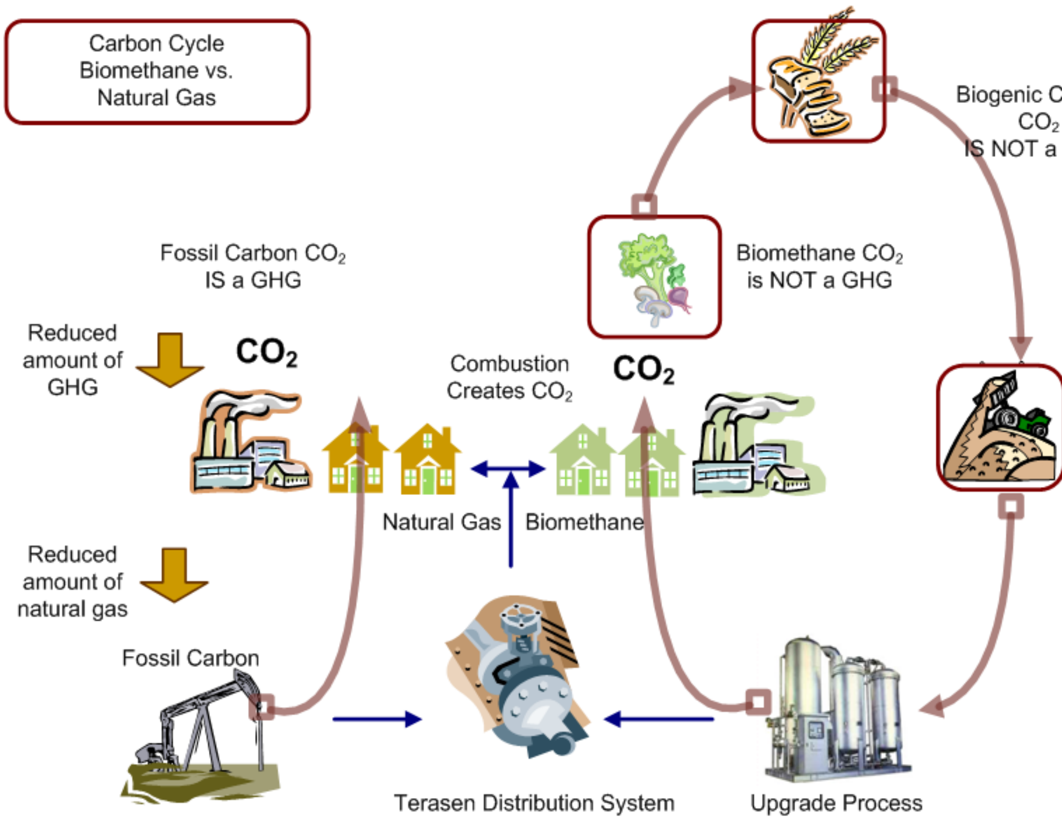
The carbon cycle is similar for other waste streams such as agricultural waste. Agricultural waste could either release methane directly into the atmosphere (if it is not carefully managed) or it can be aggregated in a digester. Once it is collected in a digester the agricultural waste would generate Biogas which could be used similarly for consumption in end uses.

2.7.3 DISPLACEMENT OF CARBON POSITIVE ENERGY SOURCE

Conventional natural gas and the CO_2 produced from its combustion are considered to be GHGs because they add to the total amount of CO_2 in circulation in the atmosphere. This occurs once natural gas is removed from an underground source (that which would not naturally end up in the atmosphere) and it is combusted. In addition, any methane released in the transportation process is considered to be GHG emission. By replacing conventional natural gas with Biomethane in end use applications, all else equal, there is a net reduction in the amount of GHGs in the atmosphere.

Figure 2-7 below helps to illustrate this point by showing Biomethane and natural gas side by side.

Figure 2-7: Carbon Cycle – Biomethane vs. Natural Gas



2.8 Conclusion

As discussed in this Section, Terasen Gas believes that Biomethane can serve as a practical, readily available fuel that is interchangeable with natural gas. The Company can take advantage of an existing natural gas distribution network to displace conventional natural gas. Biomethane is a renewable source of energy because it comes from organic waste streams. The production and consumption of Biomethane is carbon-neutral, and displacing natural gas with Biomethane will reduce GHG emissions.

3 GOVERNMENT POLICY AND ENERGY OBJECTIVES

3.1 Introduction

Federal, provincial, regional, and municipal governments are increasingly focused on addressing climate change and pollution. Governments at all levels are adopting policies in favour of renewable forms of energy as a key part of the solution to help achieve these goals. This Section discusses government's policy, objectives and direction at each level and discusses how Terasen Gas' Biomethane Application supports them.

3.2 Policy Objectives Advanced by Biogas Business Model (Supply Development through to Customer Offering)

The Provincial government has specific policies favouring the development of Biogas as a renewable energy source. Terasen Gas' proposals in this Application, which include proposals for constructing facilities to upgrade Biogas to Biomethane and inject it into the distribution system, an economic test for future supply, and a Green Gas offering, all advance government policies favouring the use of renewable energy sources, the efficient use of energy and reducing GHG emissions.

This Section of the Application discusses:

- The federal, provincial and municipal governments' policies on GHGs, utilization of renewable sources of energy, and energy efficiency;
- Specific policies in relation to Biogas; and
- How this Application advances those policy objectives.

3.3 Government Policy on Greenhouse Gas Emissions, Utilization of Renewable Energy and Energy Efficiency

All levels of government have developed policies favouring the efficient use of energy and the use of renewable energy as a means of reducing GHG emissions. This section focuses on the Provincial government's policies, and concludes with a brief discussion of Federal and municipal policies that largely echo BC's policies.

3.3.1 PROVINCIAL ENERGY POLICY

The framework for provincial energy policy is the 2007 BC Energy Plan.[11] The policies set out in the 2007 BC Energy Plan have been given effect in several pieces of legislation, including the recently passed Clean Energy Act (CEA)[12].

[11] "Energy Plan 2007: A Vision for Clean Energy Leadership". A copy is included in Appendix B-2

The 2007 BC Energy Plan built on the 2002 Energy Plan,[13] which had focused on low electricity rates, energy security, private sector involvement in new electricity development, and environmental responsibility. The 2007 BC Energy Plan committed British Columbia to addressing climate change by harnessing clean and renewable energy to reduce overall GHG emissions, and to a renewed focus on the efficient use of energy sources. Recently, the provincial government's commitment to reducing GHG emissions and increasing the development of clean energy were re-affirmed in the February 9th, 2010 Speech from the Throne and through the passing of the *Clean Energy Act*.

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

- Renewable Portfolio Standards are requirements that any given supply, or portfolio, of a fuel must be composed of a standard minimum amount of fuel from a sustainable source. An example of the adoption of a Renewable Portfolio Standard by the British Columbia Provincial Government was the 2008 introduction of the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act*.[14] This act created the legal structure required to impose an escalating minimum percentage of renewable fuel in gasoline and diesel sold within the province. As of January 1, 2010, the renewable component required is 5%, and the Carbon Tax applicable to gasoline and diesel has been reduced proportionately to reflect the reduced non-renewable component of these fuels.[15]
- The *Greenhouse Gas Reduction Targets Act* ("GGRTA"), enacted in 2007, mandates reductions of provincial GHG emissions of thirty-three percent by 2020 and eighty percent by 2050 using 2007 as the baseline.[16] The GGRTA also requires all departments of the provincial government to become GHG neutral by 2010.
- *The Carbon Tax Act,* passed in 2008, further signalled the provincial government's commitment to the reduction of GHG emissions.[17] As stated on the British Columbia Ministry of Finance website, the purpose of the carbon tax "is to ensure that a consistent long term price signal is provided to consumers so that they continue to make the choices required to reduce their fossil fuel use and emissions."[18]

---

12 S.B.C. 2010, c. 22. A copy of the First Reading version of the *Clean Energy Act* is included in Appendix B-3. At the time of filing this Application this was the only version of the *Clean Energy Act* available on the Legislature's website.
13 "Energy Plan 2002: Energy For Our Future: A Plan for BC". See Appendix B-4
14 S.B.C. 2008, c. 16.
15 See Appendix B-5 for a copy of the Renewable Fuels Notice – Carbon Tax
16 S.B.C. 2007, c. 42.
17 S.B.C. 2008, c. 40.
18 British Columbia Ministry of Finance: Myths and Facts About The Carbon Tax (http://www.fin.gov.bc.ca/tbs/tp/climate/A6.htm)

- In 2008, the provincial government amended the *Utilities Commission Act* (the "Act" or the "UCA") to require the Commission to ensure that utilities undertake efficiency and conservation measures in their operations, and to consider the government's energy objectives in specified approval processes.[19] These objectives (pending the passage of Bill 17, the *Clean Energy Act*) include:

  > (a) to encourage public utilities to reduce greenhouse gas emissions;
  > (e) to encourage public utilities to use innovative energy technologies
  >
  > > (ii) that support energy conservation or efficiency or the use of clean or renewable sources of energy;

On April 28th, 2010 the provincial government introduced Bill 17, the *Clean Energy Act*. The *Clean Energy Act* was given Royal Assent on June 3rd, 2010. Pursuant to section 58 of the *Clean Energy Act*, the "British Columbia's energy objectives" set out in section 2 of the *Clean Energy Act* replace the "government's energy objectives" currently specified in the UCA:[20]

> 58 Section 1 of the Utilities Commission Act, R.S.B.C. 1996, c. 473, is amended by repealing the definitions of "demand-side measure" and "government's energy objectives" and substituting the following:
>
> "British Columbia's energy objectives" has the same meaning as in section 1 (1) of the Clean Energy Act;

A number of the "British Columbia's energy objectives", quoted below, support this Application:[21]

> The following comprise British Columbia's energy objectives:
>
> (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% less than the level of those emissions in 2007,
> >
> > (ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

---

19 Bill 15 – 2008, Utilities Commission Amendment Act, 2008.
20 S.B.C. 2010, c. 22, section 58.
21 As stated above, these are taken from the First Reading version of Bill 17 (which became the *Clean Energy Act*), which was the only available version at the time of filing this Application (see Appendix B-3).

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

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

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

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

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

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

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

(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;

(m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;

The *Clean Energy Act* places a new focus on clean bioenergy, laying the groundwork for development of this energy source in British Columbia. As the updated energy objectives will be applicable in the context of the regulation of public utilities, these amendments speak to the government's objective of involving public utilities in the targeted reduction of GHG emissions through the efficient development of clean and renewable energy, including biogas.

3.3.2 LOCAL GOVERNMENT POLICY

Local governments have responded to the provincial policy initiatives in respect of GHG reduction. On September 26, 2007, sixty-two communities across the province announced that they had signed on to the B.C. Climate Action Charter, committing to become carbon neutral by 2012.[22] By the end of 2009, 176 municipalities in B.C. (out of 188 in total) had signed the Climate Action Charter.

3.3.3 FEDERAL GOVERNMENT POLICY

While the 2005 and 2007 Climate Action Plans differed in their commitment to the Kyoto Treaty, they both showed the federal government's intention to reduce GHG's and provided similar

[22] See Appendix B-6 for a copy of the news release announcing sixty-two communities' commitment to carbon neutrality

strategies for doing so. The federal government's commitment to reducing GHG emissions was re-stated in the March 3rd, 2010 Speech from the Throne.[23]

Terasen Gas is committed to adherence with government policies, and believes that the principles discussed above are in keeping with the Biogas and Biomethane developments proposed in this Application.

3.4 Specific Government Policy on Biogas

Finally, the Provincial Government has explicitly stated its support for Biogas project development in the 2008 Bioenergy Strategy. The Bioenergy Strategy states that "Government and its partners will collaborate to develop B.C. bioenergy projects utilizing energy from wood waste, agriculture, renewable fuels and municipal waste".[24] As noted previously, the CEA includes a "government energy objective" relating to biogas, and other "government energy objectives" (currently in the UCA and in the CEA) also support the upgrading of raw Biogas to Biomethane.

3.5 How this Application Delivers on Public Policy Direction

The proposals in this Application will promote the development and use of Biogas to help meet customer demand for energy. The development and use of Biogas as an energy source advances the policy objectives outlined above because of the following three attributes of Biogas and Biomethane discussed in Section 2 of this Application:

- Biogas is a renewable energy resource, and upgrading Biogas to produce Biomethane is the most efficient use of that renewable resource;
- the production and use of Biomethane is carbon neutral; and
- the use of Biomethane in place of a GHG-positive energy source (such as natural gas) results, all else equal, in a net reduction in GHGs.

In this Section, we draw a clear link between these attributes and government's energy objectives. We also discuss how the proposals in this Application will assist local governments.

3.5.1 GOVERNMENT'S ENERGY OBJECTIVES

Table 3-1 below identifies the relevant energy objectives that will now apply pursuant to the *Clean Energy Act*. The right hand column explains, in summary form, why the proposals in this Application are consistent with or promote "government's energy objectives".

---

[23] "A Stronger Canada. A Stronger Economy. Now and for the Future. Speech from the Throne to Open the Third Session of the Fortieth Parliament of Canada" March 3, 2010. Found at http://www.speech.gc.ca/grfx/docs/sft-ddt-2010_e.pdf

[24] BC Bioenergy Strategy – Growing our Natural Energy Advantage, 2008 (see Appendix B-7), p.8.

Table 3-1: How This Application Conforms to the Clean Energy Act

"Government Energy Objective"	Reference to Clean Energy Act (CEA)	How Terasen Gas' Proposals Address "Government's Energy Objective"
"to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources"	CEA s.2(d) (similar to current objective in section 2(e) of UCA)	Terasen Gas is proposing to create a market for Biomethane, a currently unused innovative source of clean and renewable energy in British Columbia. Further, the use of made-in-BC technology is proposed for one of the projects described in Section 8 of this Application.
"to reduce BC greenhouse gas emissions…"	CEA s.2(g) (similar to current objective in section 2(a) of UCA)	As detailed in Section 2.7.2 of this Application, the development and use of Biomethane is carbon neutral. The use of Biomethane in place of a carbon positive energy source, such as natural gas, will lead to reduced BC greenhouse gas emissions.
"to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia"	CEA s.2(h)	As detailed in Section 2.7.2 of this Application, the switching from conventional natural gas to Biomethane will lead to reduced BC greenhouse gas emissions.
"to encourage communities to reduce greenhouse gas emissions and use energy efficiently"	CEA s. 2(i)	As discussed immediately below and in Section 9, Terasen Gas proposes to partner with municipalities and regional districts to allow them to reduce their greenhouse gas emissions through the upgrading of their waste methane (Biogas) to pipeline quality Biomethane.
"to reduce waste by encouraging the use of waste heat, biogas and biomass"	CEA s. 2(j)	The upgrading of currently wasted Biogas to Biomethane, and its injection in to the Terasen Gas distribution system, will allow its use by customers on the Terasen Gas distribution system.
"to encourage economic development and the creation and retention of jobs"	CEA s. 2(k)	The Company is proposing to use made-in-BC technology for the Salmon Arm landfill project described in Section 8 of this Application. The Catalyst Power Inc. project proposed in Section 8 of this Application is directly creating the employment of the entrepreneurs who are responsible for the development of that project.
"to foster the development of first nation and rural communities through the use and development of clean or renewable resources"	CEA s. 2(l)	Terasen Gas proposes to partner with municipalities and regional districts, and will seek out further such partnerships that may also include First Nations communities for the development of clean and renewable Biomethane supply projects.

3.5.2 LOCAL GOVERNMENTS AND LANDFILLS

Many of the logical partners for Terasen Gas in the development of Biomethane projects are municipalities or regional districts. This is because landfills and sewage treatment facilities owned and/or operated by municipalities or regional districts are often excellent sources of raw Biogas. This Biogas presently represents a GHG emission liability for local governments due to their commitment to reduce GHG emissions. The capture of Biogas, and its upgrading to pipeline quality Biomethane, can help local governments generate revenue and meet the municipal GHG emission targets through the beneficial use of waste methane rather than flaring it. An excellent example of this can be found in the description of the Columbia Shuswap Regional District landfill Biogas project in Section 9.2 of this Application.

Our relationships with municipalities and regional districts have led us to believe that local governments would prefer to work with large, experienced organizations such as Terasen Gas. Local governments, as a result of the nature of their mandate, are highly risk-averse organizations which have shown a preference for partnership with stable, experienced, transparent, and safety-oriented organizations such as Terasen Gas.

In many instances, Terasen Gas will be the only logical partner for the economic transportation of upgraded landfill gas, given that landfills are often located in less populated areas some distance away from potential purchasers. The breadth of TGI's distribution system will mean that the system is proximate to populated areas (markets) as well as many sources of biogas.

3.6 Conclusion

The government policies in jurisdictions in which Terasen Gas operates have evolved, with a strong focus on the use of renewable energy, energy efficiency, and reduction of GHG emissions. The proposals in this Application will support government policy by promoting the supply and upgrading of Biogas, and by providing our customers with access to a Green Gas product.

8 SUPPLY SIDE BUSINESS MODEL

8.1 Introduction

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

This Section provides:

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

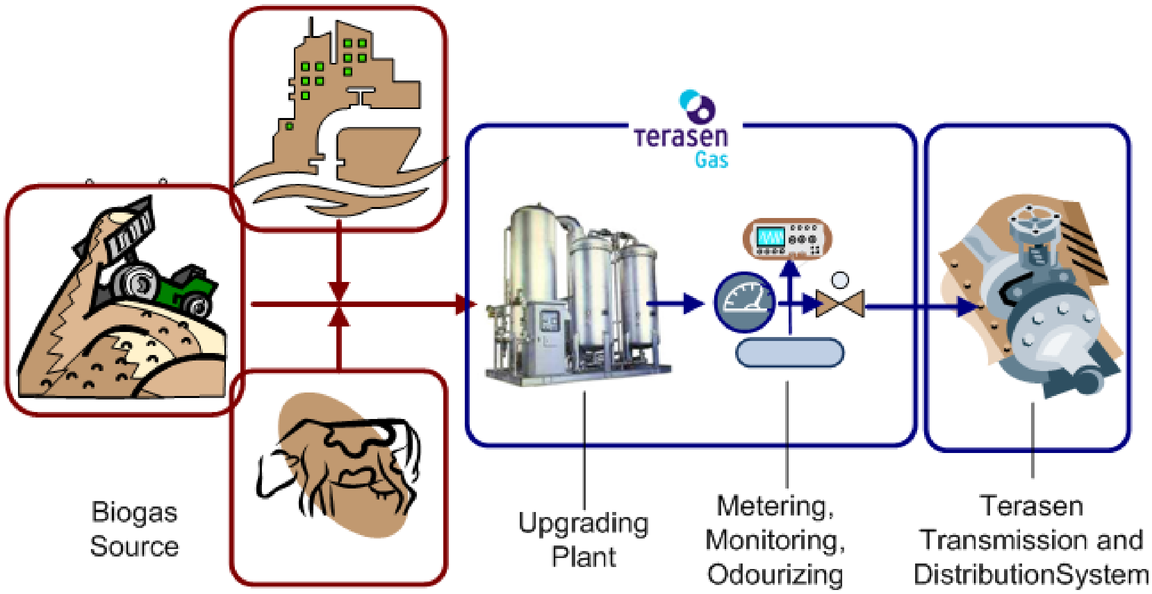
8.2 Ownership Model

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

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

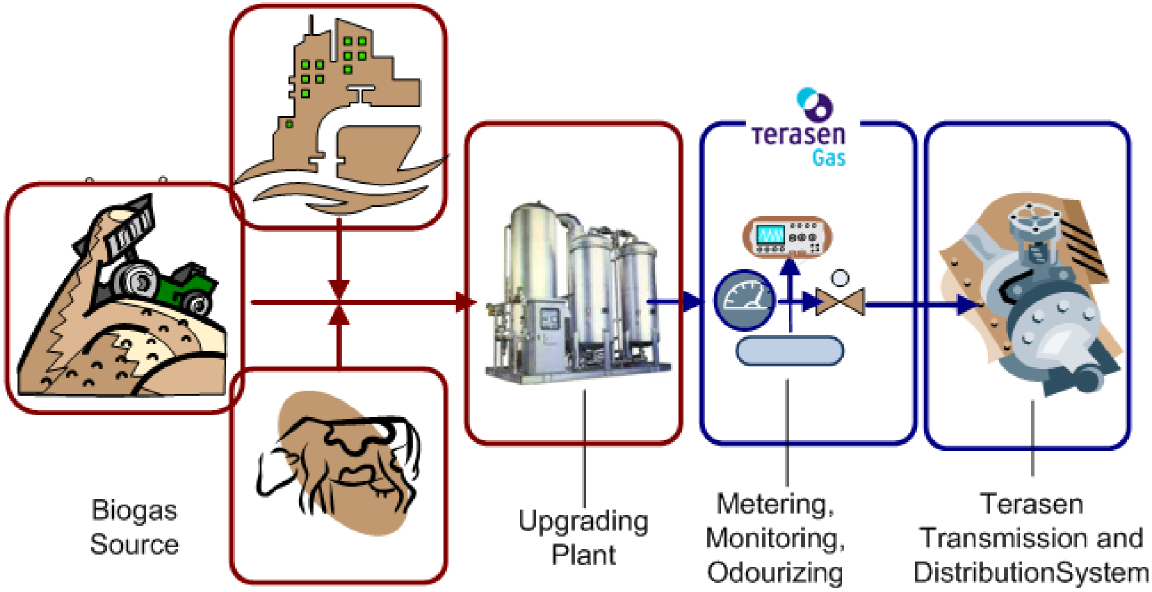
Terasen Gas is purchasing raw Biogas, and is upgrading it to Biomethane for injection into the Terasen Gas system. An example of would be a municipal operation that produces Biogas that would otherwise be wasted, but lacks the capital or experience to operate upgrading equipment.

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



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

Figure 8-2: Exception to Ownership Structure



8.3 Scope of Terasen Gas' Involvement in Two Supply Models

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

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

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

8.3.1 PARTNER WILL OWN BIOGAS SOURCE OR DIGESTER

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

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

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

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

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

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

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

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

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

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

8.3.2 TERASEN GAS OWNERSHIP AND CONTROL OVER UPGRADING FACILITIES

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

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

The key features of this model are as follows:

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

Advantages:

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

Disadvantages:

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

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

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

8.3.3 TERASEN GAS OWNERSHIP AND CONTROL OF INTERCONNECTION FACILITIES

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

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

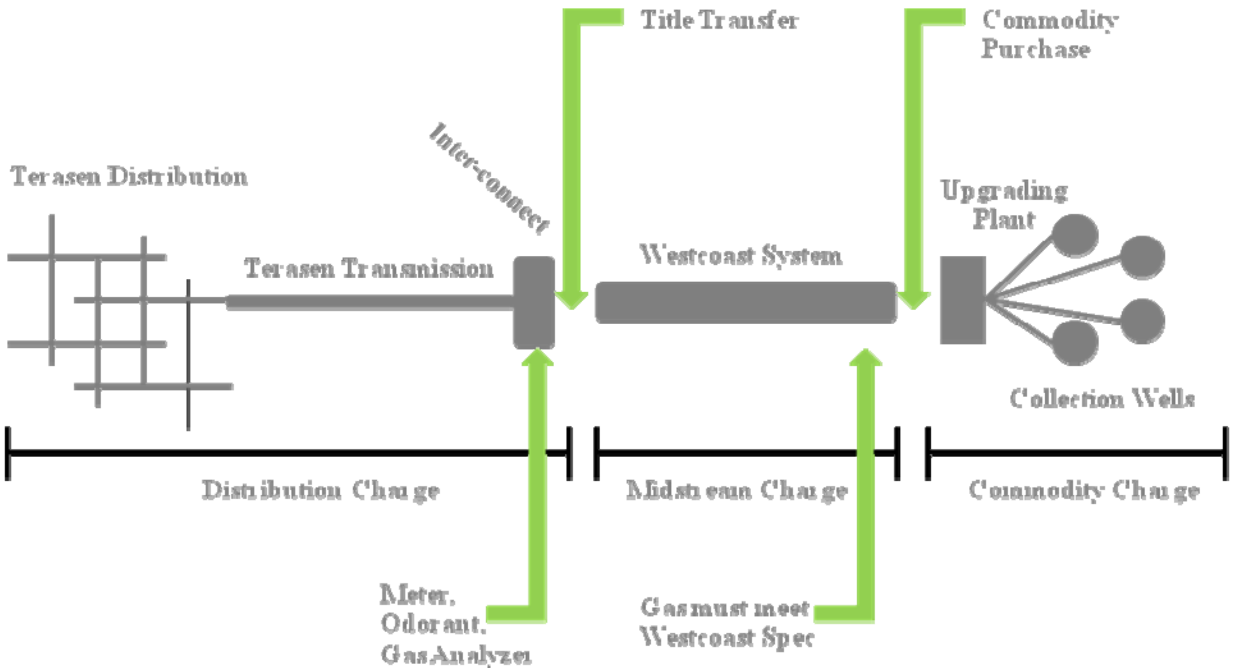
Terasen Gas must in all cases retain ownership and control over the interconnection in order to ensure the safety and reliability of the Terasen Gas system.

8.3.4 COMPARISON TO TERASEN GAS' CURRENT NATURAL GAS SUPPLY CHAIN

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

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

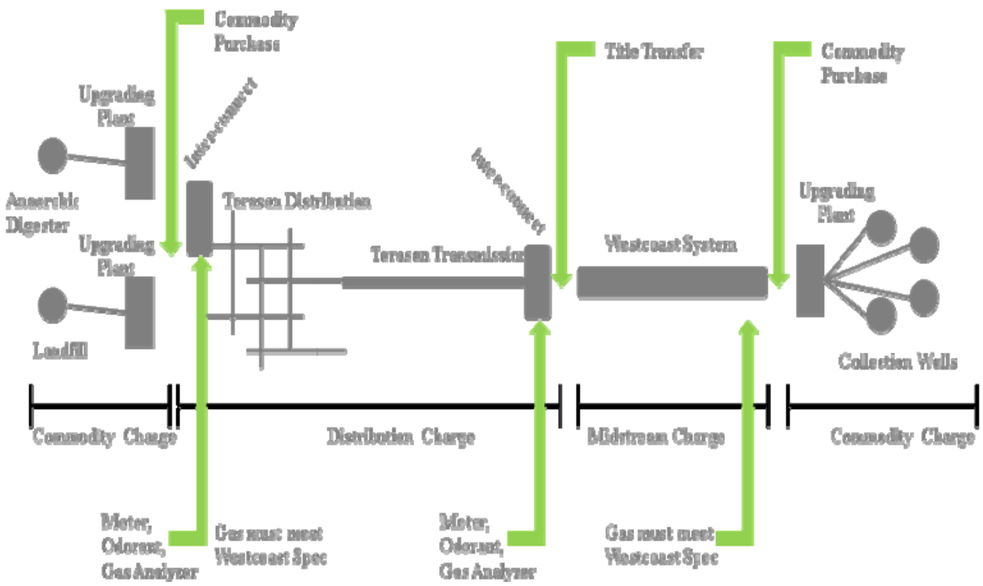
Figure 8-3: Current Structure of Natural Gas Supply Chain and Cost Recovery



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

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

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



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

8.4 Assessment of Future Projects

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

8.4.1 GUIDING PRINCIPLES FOR DEVELOPMENT OF BIOMETHANE SUPPLY

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

A) Project Economics

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

B) Gas-Processing Technology

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

C) Working with Biogas Project Proponents

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

D) Cost Recovery

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

E) Gas Quality

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

F) Injection Location

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

G) Contract Length

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

H) Project Design for Mobility

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

I) Investment Arrangement

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

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

8.4.2 MAXIMUM BIOMETHANE COST

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

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

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

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

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

Table 8-1: Proposed Maximum Unit Cost

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

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

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

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

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

8.4.2.2 Alternatives Considered for Economic Test

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

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

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

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

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

[85] BCH F2011 RRA, Appendix A1, Page 3, Line 7

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

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

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

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

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

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

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

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

8.4.3 REGULATORY REVIEW OF NEW SUPPLY PROJECTS AND CONTRACTS

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

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

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

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

8.4.4 POST IMPLEMENTATION REVIEW

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

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

8.5 Essential Services Model (ESM) Stays Intact

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

8.6 Conclusion

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

Appendix D

TERASEN GAS PRIMARY RESEARCH STUDY

RFP:P091794GRW - Green Gas Study
Quantitative Proposal

Date September 18, 2009
R1547/MA/GK

Presented to:
Terasen Gas Inc.

infocanada@tns-global.com
www.tns-global.com

Contents

At TNS, we know that being successful in today's dynamic global environment requires more understanding, clearer direction and greater certainty than ever before. While accurate information is the foundation of our business, we focus our expertise, services and resources to give you greater insight into your customers' behavior and needs.

Our integrated, consultative approach reveals answers beyond the obvious, so you understand what is happening today – and what will happen tomorrow. That is what sets TNS apart.

Thank you for allowing us to explore your business needs. The comprehensive program that follows is designed to help you achieve your goals. We hope you will trust TNS to provide the insight you need to sharpen your competitive edge.

1.0 Form Of Proposal

1. REFEERENCE:		**P091794GRW**	
PROJECT:		Green Gas Study	
CLOSING TIME:		Friday, September 18th, 2009	
		12:01 PT (Pacific Time)	
		Proposals are irrevocable and open for acceptance by Terasen for a period of sixty (60) calendar days from the Closing Time.	
NAME OF BIDDER:		TNS Canadian Facts	
ADDRESS:		610-1140 West Pender Street, Vancouver, BC V6E 4G1	
PHONE:	(604) 668-3344	FAX:	(604) 668-3333
GST Number:	137057352	BCSST Number:	N/A

2. PRICING REQUIREMENTS GST and BCSST (If applicable) included in prices below:

Proposal pricing to include GST only.

Cost to perform study within the timelines.

If multiple scenarios are proposed then provide pricing for each scenario. Outline any contractors against each scenario.

Scenario 1: $ 21,000 with N=800

Scenario 2: $23,100 with N=1,000

Scenario 3: $25,200 with N=1,200

Please refer to page 20 for more information on pricing.

A. Bidder's Qualifications

The Bidder shall submit the following information. If the Bidder is a joint-venture or limited partnership, all information required shall be submitted for each participant in the joint-venture or limited partnership.

1. Name	TNS Canadian Facts
2. Incorporated, Partnership or Sole Owner	Incorporated
3. Date of Incorporation or Partnership	November 17, 1993
4. Registered Address	610-1140 West Pender Street, Vancouver, BC V6E 4G1
5. Subsidiary Of:	WPP Group plc
6. If bid bond requested by Terasen name and address of bonding company if a certified cheque and not a bid bind is submitted with the Proposal.	N/A

7. The Bidder's Workers' Compensation Board ("WCB") information is as follows:

7.1 WCB Experience Ranking System (ERA)

Previous 3 years	N/A

7.2 WCB Inspection Report Summary

Previous 3 years	N/A

B. Subcontractor's Information

There will be no subcontracting on this project.

C. Bidder's References

The Bidder shall list three (3) references from Work of similar nature to this Project which it has recently completed or is now conducting.

Reference	Work Description	Phone Number
Eddie Van Dam BC Hydro	Manager, Research Services	(604) 623-4536
Shashi Maharaj (alternate) BC Hydro/Power Smart	Power Smart Evaluator	(604) 453-6316
Marshal Wilmot Rogers Plus	Vice President, Marketing	(604) 644-1027
Nancy Norris BCTC	Policy Analyst	(604) 699-7463

Please refer to page 26 for more information about the projects that were done.

3. The bidder agrees that all work shall be performed in accordance with the Workers' Compensation Act of the Province of British Columbia; the Bidder's Workers' Compensation Board Registration Number is C124722476.

4. In the event that Terasen issues any addenda please acknowledge receipt below:

Addendum#	Date Received
N/A	

5. This section MUST be completed for the Bidder's Proposal to be considered.

5.1 We confirm that we accept in their entirety the terms and conditions in Part 4 of the *RFP: Green Gas Study / Reference: P091794GRW* and agree to be bound by them.

5.2 The Bidder must check on of the boxes below as appropriate:

- ☑ We accept the Scope of Work described in Part 2 of the *RFP: Green Gas Study / Reference: P091794GRW.*
- ❑ We accept the Scope of Work described in Part 2 of the *RFP: Green Gas Study / Reference: P091794GRW* with the following specific exceptions:

7. In Witness Whereof the Bidder has executed this Proposal the 18 day of September, 2009.

Authorized Signatory	Authorized Signatory
Dr. Michael Antecol	Gerry Keane
Print name	Print name
Vice President	Research Director
Title	Title

2.0 Corporate Information

2.1 Principal Contact

The principal contact and liaison person for this study will be:

Dr. Michael Antecol

Vice President

1140 West Pender Street, Suite 610

Vancouver, British Columbia, V6E 4G1

Tel. 604-668-3306

2.2 Location Of Head Office And Support Offices For TNS Canadian Facts

TNS Canadian Facts Inc.

Toronto (Head Office)
900 – 9 Bloor Street East
Toronto, Ontario, M4W 3H8
Tel: 416.924.5751
Fax: 416.923.7085

Vancouver
1140 West Pender Street, Suite 610
Vancouver, British Columbia, V6E 4G1
Tel: 604.668.3344
Fax: 604.668.3333

Montreal
1250, rue Guy, Bureau 1030
Montreal, QC, H3H 2T4
Tel: (514) 935-7666
Fax: (514) 935-6770

Ottawa
55 Murray Street, Suite 210
Ottawa, Ontario, K1N 5M3
Tel: (613) 230-4408
Fax: (613) 232-7102

2.3 Corporate History And Size Of Organization

TNS Canadian Facts is one of Canada's largest marketing and social research firms. Our roots go back to 1932 when Canadian Facts was established as the country's first survey research organization. Today, we have offices in Toronto, Montreal, Ottawa and Vancouver, with 170 full-time members of staff.

We are a TNS company[1], the world's largest custom marketing research firm and the world's largest provider of Internet-based custom marketing research. We provide market research measurement, analysis and insight in more than 110 countries.

Over our long corporate history, our primary activity has remained the same: the conduct of research investigations to provide our public and private sector clients with information and strategic direction.

1 TNS Canadian Facts has been a part of TNS plc since 2003. TNS plc has been part of The Kantar Group since October, 2008.

Marketing and opinion research has grown dramatically in Canada since 1932. Throughout the years, we remained committed to the needs of our clients and dedicated to the development of progressive research systems. Allied to expert client service, the company offers a comprehensive range of research services, technical expertise and specialized facilities, catering to the broadest spectrum of research needs.

Toronto is the head office and control centre for data collection, sampling, quality control and data processing departments. TNS Canadian Facts, Vancouver, offers knowledge and expertise to clients interested in western markets. The Montreal office is completely bilingual and provides specialized expertise to clients interested in the French-Canadian market. The Ottawa office provides specialized assistance on assignments for the federal government. The company was incorporated in the Province of Ontario on November 17, 1993—Provincial Charter No. 1052289.

An overview of our history in Canada is depicted in the diagram to follow.

1930s
- Company founded, 1932
- Field force established, 1937

1940s
- Establishment of Montreal office, 1948
- First national probability sample, 1948

1950s
- First omnibus survey - The Big 8M/CF Monitor, 1956
- Canadian Family Opinion - national mail panel, 1960

1960s
- Consumer Opinion Centres - mail interview facilities, 1964
- First in-computer facilities, 1964
- Establishment of Vancouver office, 1965

1970s
- Merger with Stevenson Kellogg, 1973
- Establishment of Ottawa office, 1974

1980s
- Integration of ABT Associates of Canada, 1986
- Installation of CF FACTS Network, 1986

1990s
- Integration of Burke I.R., 1991
- Formation of CF Group Inc., 1993
- Part of NFO Worldwide Inc., 1998

2000s
- Part of IPG, 2000
- Part of TNS, 2003
- Part of WPP 2008

2.4 Parent Company: TNS plc

Who we are:

- World's largest custom research business
- Second largest global market intelligence company
- Global network spanning over 80 countries
- Operating in 110 countries worldwide
- Over 14,000 employees
- Over $1.85 (US) billion in 2006
- Listed on the London Stock Exchange (TNS.L)
- Global leader in customer stakeholder management research
- Global leader in opinion polling and social research
- World's largest consumer panel research group

TNS is one of the world's leading market information groups, providing market measurement, analysis and insight through its operating companies in 80 countries. Working with national and multi-national organizations, we help our clients develop effective business strategies and enhance relationships with their customers.

TNS provides full-service, primary market research. Our mission is to become our clients' sixth sense of business™ by giving them a deeper understanding of their customers' behavior, better anticipation of their actions and greater insight into what they really want. We use an integrated, consultative approach to get beyond the obvious and design a comprehensive plan that meets our clients' needs now and in the future.

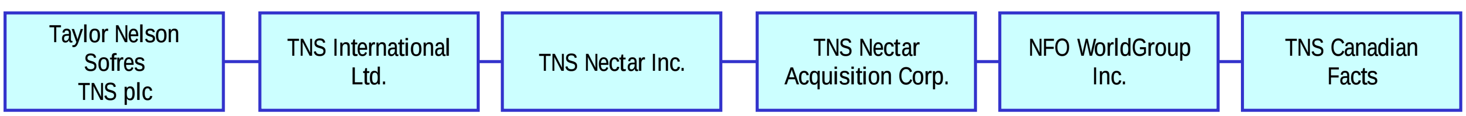
TNS plc has office locations in over 80 countries, as depicted in the map to follow:

An overview of the corporate profile for TNS plc is as follows:

- The 1960s saw the creation of five of the market research companies that are at the heart of the Taylor Nelson Sofres (TNS) Group today:
  - Intersearch in the USA in 1960
  - AGB in the UK in 1962
  - Sofres in France in 1963
  - Frank Small Associates in Australia in 1965
  - Taylor Nelson in the UK in 1965
- But the very first seeds have been sown in the USA in 1946, when NFO (National Family Opinion) opened for business.

- In the 60s, 70s and 80s, all these companies grew significantly, introducing a wide and increasingly sophisticated range of research solutions and using the latest technological developments. And as their clients grew, they started to create their international networks.
- Key developments:
    - Sofres opened offices in six European countries, the US and 12 countries in Asia Pacific.
    - Taylor Nelson and AGB each developed a UK network of offices and began to acquire businesses in Europe.
    - NFO grew to become the by-word for managed access panels in the USA.
    - It soon became clear that brands were becoming global, and brand owners would need global market information partners. In the 1990s, the market research industry started to consolidate, as major clients demanded an increasingly international service.
- NFO made a series of acquisitions around the world and the companies that now form TNS responded to the changing market by joining forces, enabling them to deliver consistently high quality services to customers around the world.
    - Sofres acquired Secodip (1992)
    - Taylor Nelson joined with AGB (1992)
    - Sofres combined with FSA (1995)
    - Sofres acquired Intersearch (1997)
    - Taylor Nelson AGB and Sofres merged (1997)
    - TNS acquired NFO (2003)

The corporate legal structure of TNS plc is depicted in the following diagram:



The address for the head office of TNS plc is:

- **Head Office**
  TNS House
  Westgate
  London, England W5 1UA
  Tel: +44 (0) 208 967 4551

2.5 Core Competencies

TNS recognizes that our clients need a partner with world-class expertise and innovative thinking in specialist areas of research. We have responded to that demand by positioning our custom business to meet these needs, within the following areas of expertise:

- **Product Development And Innovation**

  Product development and innovation services help clients identify new opportunities, evaluate whether an idea justifies investment, discover how to make a concept more appealing, optimize the product mix and forecast potential sales volumes often using tools such as Discrete Choice Modelling (DCM). It covers the product development process from idea generation, early stage screening, concept and product optimization through to volumetric forecasting and post-launch evaluation.

- **Customer Satisfaction / Stakeholder Management**

  Stakeholder management helps clients measure and monitor their performance and relationships with various stakeholder groups. Clients are particularly interested in understanding factors affecting levels of satisfaction, retention and motivation of customers and employees. TRI*M™, the main TNS solution in this area, offers actionable recommendations to boards and senior management teams.

- **Brand And Communications**

  Brand and communications services help clients build their brands through every stage of the brand experience, from development to implementation of strategy. TNS also tracks the success of brands and communications in the marketplace, with a view to optimizing brand performance and maximizing future potential.

- **Retail And Shopper Insights**

  Retail and shopper provides insight about in-store and shopper behaviour for manufacturers and retailers. These insights can be used to improve equity, sales and profitability of a brand or category through merchandising, store layout, pricing and promotions, as well as in-store communications.

- **Customer Intelligence**

  Customer intelligence provides insight based on analysis of multiple data sets, combining behavioural information at an individual or household level. This delivers insight about our client's customers in areas such as customer profitability, defection risk and propensity to buy. Fusing this with TNS information such as usage and attitudes can then be used to drive more tailored marketing.

Our areas of expertise include, but are not limited to:

- Consumer Panels
- Interactive Surveys
- Stakeholder Management
- Polling And Social
- Finance
- Technology
- Segmentation And Positioning
- Media
- Consumer
- Brand And Advertising Research
- Healthcare
- Energy And Conservation
- Automotive
- New Product Development
- TV & Radio

2.6 Location Of Offices For Project Team Members

The project team members proposed for this project are all based in our Vancouver office. We are supported by our operations departments in Toronto, and can draw support from other offices in Canada, or internationally as required. Telephone interviewing, if any, would be conducted from TNS Call Centres located in London (ON), Montreal (QU) or Bathurst (NB).

3.0 Experience And Expertise

3.1 TNS Canadian Facts Understands The Canadian Energy Sector

To follow are some examples of work that we have done in this sector within the past three years, including projects with Terasen Gas:

Terasen Gas – Alternative Energy Interviews (2009)

TNS Canadian Facts conducted 14 in-depth interviews about alternative energies across BC. This project assessed overall awareness of and interest in the use of such energy.

BC Hydro Power Smart Focus Groups (2009)

TNS Canadian Facts conducted 5 focus groups with BC Hydro customers who subscribed to the Team Power Smart program. In an effort to spread an energy efficiency ethic throughout BC using word-of-mouth, BC Hydro created the Power Smart Ambassador program. The focus groups explored how potential Power Smart Ambassadors responded to the program concept and general public reactions to the program concept.

BC Hydro Customer Satisfaction Survey (2009)

TNS undertakes an annual large-scale tracking survey for BC Hydro in British Columbia. The customer satisfaction survey runs for 52 weeks of the year and surveys over 5,800 customers, both residential and business. The reports provided by TNS include the key benchmarks used by the Board of Directors to monitor satisfaction among a population of over 1.5 million customers.

In addition to collecting data and producing the key performance reports, TNS provides analysis and interpretation on a quarterly basis, to assist the company in its C-Sat strategy.

Union Gas (1987 to present)

Annual Residential Market Share Tracking research is conducted among Union Gas' residential customers. 1,400 telephone interviews are conducted across Ontario with quotas by region. For many years the deliverables included a full written report and data. Currently the client handles its own reporting. Each year the survey evolves to address new areas of interest, while retaining key tracking metrics.

Consumer DSM Post-Advertising Measure (2008)

BC Hydro commissioned TNS Canadian Facts to conduct a post-advertising measure for the "Join Team Power Smart" advertising campaign. A total of 524 online interviews were conducted among British Columbia residents aged 18 years or over to determine awareness of the ads, and impact on energy conservation attitudes and behaviours.

Qualitative Study with Psychographic Segmentation of BC Hydro Customers (2008)

Focus groups were conducted to understand in greater depth how various customer segments think about and use electricity, and how they might be persuaded to use less of it. Conducting these focus groups also allowed these segments to be qualitatively validated and compared. A total of 53 BC Hydro customers participated in these groups, which were moderated by Linda Dethman.

Challenge Focus Groups (2008)

In July and August 2008, we conducted six focus groups for BC Hydro to gather opinions and experiences from participants in two behavioral change challenges targeted to local governments. The results of the study were used to guide future initiatives targeted to local government stakeholders. The groups included 30 representatives from local governments, and were moderated by Linda Dethman.

Smart Metering (2008)

Six focus groups among BC Hydro's residential customers were done to assess perceptions and reactions to various aspects of the "Smart Meter Infrastructure" (SMI) Program roll-out. The first four groups were conducted in-person at a professional focus group facility in Vancouver and included customers from the Greater Vancouver area. The second two sessions were on-line groups, where the moderator and participants communicate via the Internet. This approach allowed wider geographic coverage, and customers from diverse locations such as Bella Coola, Victoria, and Quesnel participated. The focus groups were co-moderated by Linda Dethman with Marina Gilson.

Corporate Satisfaction and Image Study (2004 to present)

A corporate satisfaction and image study is conducted annually by telephone with BCTC's key stakeholder groups, including provincial government officials, municipal representatives, and customers. Additionally, the TNS online panel was used to poll public stakeholders. In total, 1,375 interviews are conducted per wave. Separate sets of recommendations were made for each stakeholder group to provide strategic direction for improved performance and perceptions among each of the groups.

Terasen Gas Corporate Image Study (2004/2006/2008)

In order to develop a strategy to manage its corporate image, Terasen Gas retained TNS Canadian Facts to conduct a customer satisfaction and brand equity study with its key stakeholders. This study takes place on a two-year cycle. This study surveys 850 Terasen customers and 60 'influencers': elected and administrative provincial / municipal government officials. The study is fielded via telephone. Through TRI*M and Conversion Model analyses, the study identifies specific areas of focus and communication strategies for improving corporate image.

Terasen Gas Ad Tracking (2007/2008)

In 2007 and 2008, TNS Canadian Facts undertook a continuous advertising tracking study for Terasen Gas to measure the effectiveness of an extensive radio and tv campaign. In addition to measuring key ad metrics through telephone interviews, the survey investigated householders' attitudes and perceptions towards home energy sources and natural gas in particular. The study was the key benchmark used by the British Columbia Utilities Commission in measuring the effectiveness of communications about the de-regulation of the natural gas industry in British Columbia.

Large Industrial DSM Initiative (2007)

Telephone interviews were conducted among large industrial customers of a major Canadian natural gas utility servicing northern, southwestern and eastern Ontario to assess awareness and participation in an energy program. The survey included awareness of various specific energy programs, energy efficiency targets and payback period. The factors leading to program participation were also determined.

Annual Residential Market Share Tracking (1987 to present)

Research is conducted among residential customers of a major Canadian natural gas utility servicing northern, southwestern and eastern Ontario. Each wave consists of 1,400 telephone interviews conducted across Ontario with quotas by region. Each year the survey evolves to address new areas of interest, while retaining key tracking metrics.

3.2 TNS Canadian Facts Understands Discrete Choice Modelling:

These are some examples of work that we have done using the Discrete Choice Model in the past three years:

New Conjoint Study (2009)

Rogers Plus was facing competitive pressures from a direct competitor who aggressively lowered their prices while extending their rental durations on new releases. To understand how the competitors latest offer would impact switching behaviour among movie renters, a market study was undertaken with customers of both chains. A discrete choice modelling exercise was conducted to understand what offerings movie renters value most, at what price point and how our client should proceed in response to their competition's new offering. A total of 2,395 online interviews were conducted with movie renters at each major chain and among those that might rent elsewhere (e.g., independent movie rental stores).

Work Place of the Future (2009)

TNS Canadian Facts helped a major financial institution look at what their future physical workplace might look like if innovations were given an in-depth exploration. The workplace improvements that were examined would potentially positively affect employee work-life balance, productivity, engagement and turnover. The study explored eight different aspects of a physical workplace and featured a Discrete Choice Model that defined the workplace features most important to associates. TNS Canadian Facts administered an online survey with banking associates from two urban regions in mid June of 2009. Of the 1,437 surveys that were completed, the breakdown was 1,041 by Corporate employees (+/- 1.7% margin of error, nineteen times out of 20) and 396 by Branch employees (+/- 4.1% margin of error, nineteen times out of 20).

Video Brand Survey (2008)

Rogers Plus commissioned TNS Canadian Facts to conduct an online survey to determine the awareness level of its new rental program among its customers and non-customers. A discrete choice model was also part of the study to come up with a share of preference simulation for all movie rental package elements and pricing levels. Separate share of preference simulations have been produced for Rogers Plus customers and Rogers Plus non-customers, as these two groups tend to be differ in their opinions.

4.0 Project Methodology & Management

4.1 Moving Toward Smart Research: Our Guiding Principle

Currently, Terasen Gas (TG) primary business activity involves the delivery of natural gas and piped propane to homes and businesses throughout British Columbia. Indeed, 95% of natural gas customers in the province receive their gas via TG. But, at least two major changes are afoot in the energy sector: (1) the energy marketplace is becoming increasingly competitive and (2) environmental issues are increasing in importance among both the public and TG customers. As a result, TG is repositioning itself as a diverse energy solutions provider that can be both competitive as well as environmentally friendly (i.e., by minimizing the environmental impacts of its activities).

It is from this perspective that TG has issued RFP P091794GRW (the "RFP"). Specifically, one of the avenues that TG is exploring is the provision of a *Green Gas* program among residential customers whereby TG would "transform" biogas produced from landfill, waste treatment plants, cow manure and other organic waste products into pipeline quality natural gas for distribution to its customers. At the same time, TG is also developing biomethane supply, creating offset projects and building a full-scale green product offering.

The purpose of the above-mentioned RFP is straightforward from one perspective: *Terasen would like to better understand the potential market for green gas, its market drivers and other factors affecting different price points.* Successfully doing so will help TG to satisfy several of its Environmental Commitments, namely:

1. Integrating environmental protection measures into all elements of its business;

2. Using resources efficiently and effectively;

3. Setting targets and objectives for environmental performance; and,

4. Incorporating … environmental performance measures into its corporate goals, objectives and employee compensation systems.

There is no doubt that TNS Canadian Facts can perform the tasks pursuant to this RFP that will allow TG to follow through on the above-mentioned objective and commitments. At a certain level, though, if that was all we did, we would be nothing more than a data provider that follows instructions and communicates in a timely manner. But, it is clear from the RFP that TG desires more than a mere order-taker in a research supplier.

It is TG's planned use of the data that moves this RFP from straightforward data collection and analysis to a more complex and rigorous project – one that requires a research supplier to be a consultant, to add value, to determine the WIM (What It Means) of the data. That planned use is:

> *Findings from the study will help the project team determine the appropriate product offerings by identifying the right customer segment(s), factors affecting their decision making and the right pricing*.

It is here that TNS Canadian Facts can offer much more to TG and add value to the project: we can offer *Smart Research*. We implement *Smart Research* by taking a consultative approach to business issues that require market research. By diving deep into our clients' issues we can not only deploy the full range of business solutions at our disposal, but, more importantly, we can pick the right solutions, or combination of solution, for each particular situation. We will do the same, when successful in this bid, with TG.

4.2 *Smart Research* And Terasen Gas: The Recommended Approach

Above, we introduced the concept of *Smart Research* – our guiding principle. Here, we provide a roadmap on how to implement such a research project for TG. The first step in moving in this direction, is to understand the specific objectives of this study:

1. Determine the market interest;
2. Determine the potential target market and market size;
3. Develop clear and concise customer profile(s);
4. Determine market drivers;
5. Determine price points and factors affecting price points; and
6. Understand customer perceptions on different product offerings (i.e., offsets, biomethane).

From our point of view, it is important to uncover the answers to the above points from both TG customers and non-customers. Developing this new business line may require a two-sided strategy – (1) increasing spend among current customers for environmentally-friendly alternatives and (2) converting over non-customers to TG.

However, the ultimate solution may be even more complicated: *commitment* to the environment may be an important overriding factor. We need to know what drives those who are *committed* and those who are *uncommitted*. Why? Because those who are committed to the environment, whether current TG customers or not, are likely the best targets for this project. Conversely, those who are uncommitted will probably not be swayed, meaning any advertising dollars targeting this group would represent resources poorly spent. More on this will be covered later in the discussion on Conversion Model™ (Section 4.2.2).

4.2.1 Meeting The Objectives – Regression And Discrete Choice Modelling

There are two main ways to determine market size, target market, market interest, perceptions of product offerings and key drivers: directly or indirectly. Specifically,

1. We can directly ask respondents what is important to them to understand their attitudes, their interest, and the amount they might be willing to pay for a *Green Gas* product. After the data has been collected, we would conduct advanced statistical procedures such as OLS multiple regression to determine which elements are (or would be), in fact, the drivers of *Green Gas* uptake.

2. We can take an indirect approach; that is, we can have respondents conduct a discrete choice modelling exercise – a trade-off analysis – to ascertain the key drivers and price points.

<u>We propose to do both and compare/triangulate the results</u>.

The reason for doing both is simple: when individuals are asked scaled importance questions (e.g., how important is the environment?), there is a strong chance that many will be rated as “very important” (or, as an 8, 9 or 10 on a 10-point importance scale). Indeed, if a question is important enough to be included in the survey, it is very likely that the respondents will also find it to be important to them. **But this leads to a problem: if everything is reported to be important at the univariate level, it becomes difficult to create the final *Green Gas* product and the ancillary marketing**. In addition, these questions are all asked independently, theoretically without connection to any other questions. It is because of these facts that post-facto regressions need to be run — this procedure puts all relevant variables into the hopper at the same time in an attempt to determine the ultimate drivers.

Further, pricing is difficult to measure as a straight-up question because it can only be measured for one product or one combination of products at a time. Since the actual product could take many forms, these straight-up pricing questions – while important to ask, at least at a general level – would have to be repeated for each possibility.

To get around these issues, we would employ Discrete Choice Modelling (DCM) to help determine the optimum characteristics of such a product as well as the optimum price under different condition. TNS Canadian Facts has used DCM for a number of years to assist our clients with key marketing decisions. Indeed, TNS Canadian Facts has an extensive background in applying DCM across a wide range of respondent-types, sectors, product categories, brands and in various jurisdictions. Our Statistics Group made up of professional statisticians who are experienced in applying this analysis technique in several forms of data collection. One caveat: DCM can only realistically be done in an online survey, a point to which we will return later.

In DCM, as proposed here, respondents are asked to choose between a series of alternatives that trade-off on different features. From their choices, we are able to understand which elements weigh more heavily on their selections, and under which conditions. From this, a simulation model is built that is based on a trade-off analysis of different choice sets. This model would take into consideration various elements associated with the *Green Gas* product.

Specifically, respondents will be presented with a range of packages in a series of “choice” scenarios which are created by varying attributes, such as type of gas, offsets, availability of infrastructure and price. For each scenario, respondents answer a simple question related to two possible choices:

If these were all the choices available, which would you choose, if any?

Importantly, respondents are also allowed to choose “none”. Once the respondent finishes with one scenario, he/she moves to the next choice scenario and makes the same simple decision. This data is then analyzed via modelling and market simulation. The results of this analysis will then establish customers’ preferences and the optimal offering. (NOTE: Once the optimal offering has been chosen, we often recommend conducting a focus group to assist in marketing execution. Ideally, the groups will explore potential positive “triggers” for the package that could be used in a marketing campaign).

Because of the “choice” nature of the task, it is critical to design and present the components of the *packages* in the most efficient way, not only for the respondents but for the subsequent analysis. With DCM studies, the challenge is to present clear choices for respondents, while not reducing the number of options to being so small that all critical features cannot be individually evaluated in the analysis. As a starting point, we offer the following attributes (in bold) and levels (placed under the attributes) for consideration:

Type of Gas

Traditional natural gas
Biogas from landfill
Biogas from water treatment
Biogas from cow manure/organic waste

Infrastructure to Collect And Distribute the Gas

Built / in place
Needs to be built

Price of Gas

Same as current price
5% more than current price
10% more than current price
15% more than current price

Offsets

No
Yes – $1
Yes – $2
Yes – $3

With these attributes and levels, it is possible to envision choice sets such as the following:

	Choice 1	**Choice 2**	
Type of Gas	Biogas from landfill	Biogas from cow manure/organic waste	
Infrastructure	Needs to be built	In place	NONE
Price of Gas	10% more than current price	5% more than current price	
Offsets	No	Yes — $2	
	☐	☐	☐

We will work closely with Terasen Gas to identify the proper attributes and levels for testing. The focus will be to design a streamlined set where the elements are comprised of those that need to be "traded-off."

There are two other considerations. First, a flaw of many DCM studies is their desire to obtain full factorial measurement from too small a respondent population. This results in undue respondent burden as they have to go through many choice sets. **Solution**: have a large respondent pool. Second, as mentioned above, a DCM study has to be conducted online (it can be done in person but that would be cost-prohibitive). This means that one needs to consider the number of options that can be presented on each "screen" in the online environment: it is important that respondents see competing options on a single screen. **Solution**: we believe that two choices with a none option, as presented above, is appropriate.

Finally, see Appendix for an example of DCM.

4.2.2 Adding More Depth: Conversion Model™

Using regression and DCM we will be able to determine, directly and indirectly, the market size, target market, market interest, perceptions of product offerings and, most importantly, the key drivers of *Green Gas* uptake. However, we believe that we need to refine those results further due to the fact that TG will ultimately have to engage in both advertising and marketing to spur uptake. So, instead of gearing a campaign toward the natural gas market in its entirety, we recommend that those campaigns be geared to those consumers who are *STRONGLY OR SOMEWHAT COMMITTED* to the environment (whether or not they are currently natural gas customers or not) **AS OPPOSED TO** those consumers who are *STRONGLY OR SOMEWHAT UNCOMMITTED* to the environment. It does not make sense to market/advertise to the uncommitted as there would be relatively little uptake among that segment. It is clearly more important from an advertising and marketing point of view to look at the regression and DCM findings of those who are committed to the environment (although it is still important to investigate the uncommitted).

Accordingly, we need to identify the different levels of environmental enthusiasts (via commitment). To do this, we recommend using Conversion Model™ to measure levels of commitment for the environmental position. It should be noted that Conversion Model™:

- Is the leading commitment measure with over 8,800 studies conducted worldwide to date;
- Is used by 80% of the largest brands in the world;
- Predicts "next brand purchase" correctly 91% of the time; and,
- Tracks market share with a 90% correlation.

Using Conversion Model™ will yield the above-mentioned segments (strongly committed and somewhat committed to the environment, and strongly uncommitted and somewhat uncommitted to the environment). These segments will then be used to add more depth to the regression and DCM results.

4.2.3 Profiling

Once we have determined the possible segments, via the regression-based driver analysis and the DCM, as refined by Conversion Model™*,* we will profile those segments using demographic and other relevant criteria. This will be extremely helpful to the marketing and advertising efforts related to any proposed *Green Gas* program.

4.2.4 Alternative Consideration: Pre-Post Test

This research can also be structured to include a pre- and post-measure in order to test the effects of any upcoming advertising campaign on *Green Gas* uptake, market share, environmental commitment, etc… In the post-measure, we do not need to replicate the entire study. A smaller scale survey could be conducted that includes only the necessary measures. The benefit of at least considering this option is that TG would effectively be setting up a natural experiment regarding the effectiveness of its potential advertising campaign. This is important as experiments are truly the only way to show causation – that is, did the campaign work, or, what elements of the campaign worked.

<u>However, the quotation provided in this proposal accounts for only a one-time study to provide Terasen Gas with the strategic knowledge that it needs to develop a targeted and effective advertising campaign. We would be happy to revise the quotation if Terasen Gas would like to include the follow-up post-test study.</u>

4.3 Project Methodology

4.3.1 Research Design

As set out above, in order to conduct the DCM, the project has to be conducted online. As a result, what follows is our methodology for conducting such an online study.

4.3.2 Sample Size And Sampling

As we discussed at the outset, it would be instructive to include natural gas customers as well as non-customers. For that reason, we propose sampling the general household population (and asking them if they are current natural gas customers or not) in British Columbia.

We will use TNS's online panel in Canada. The research will be both targeted (i.e., to British Columbia) and cost effective as online surveys are more cost effective than other data collection methods. Note that TNS will offer panelists who qualify for our standard sweepstakes points.

We recommend at least 800 interviews across the province, although more would be preferred. A quota design will be implemented to ensure an appropriate number of interviews (based on population) are conducted in each part of the province. In contrast, there will not be a quota on natural gas customers vs. non-customers. Rather, we will weight the results at the end to ensure that the proper ratio is achieved (see Weighting Section, below).

Note that it would have been possible to sample from TG's customer lists (at least for natural gas customers); however, because TG does not maintain email records, this was not an option.

4.3.3 Questionnaire Development

We propose an online survey that will take no more than 15 minutes to complete. The content of the questionnaire will include the topics that have been discussed above. We will consult closely with you at the start of the study to confirm the objectives and gain a more detailed understanding of your program ideas for the first draft the questionnaire. After all, that's *Smart Research*.

4.3.4 Pre-Test

The survey will be pre-tested with approximately 5 to 10 respondents prior to a full launch. Following the pre-test, we will thoroughly de-brief with our operations staff to obtain their input on potential improvements to the questionnaire, and will discuss the outcomes with you. The questionnaire will then be modified as necessary.

4.3.5 Coding

Traditional coding and editing is required only for open-ended questions. Code lists for open-ended questions will be handled with particular sensitivity to ensure that the outcome is optimal with regard to diagnostics, within each of responding groups (e.g., customers vs. non-customers).

4.3.6 Weighting Procedure

Our weighting function is supported by full-time specialist staff including people with high-level qualifications in statistical data analysis. In combination, the staff, databases, software and hardware provide a sophisticated and reliable service to TNS Canadian Facts' clients.

4.3.7 Data Processing And Analysis

The data processing will be performed using our powerful in-house computing facilities. Although we will consult with you closely throughout the entire study, this is especially important during the analytical phase, when the detailed plan for analysis is being developed and implemented.

We will produce cross-tabulated detailed tables, using variables determined in conjunction with you. The regression based key driver analysis will be undertaken at the end of the data collection phase. Likewise, the DCM will also be conducted at that point. Conversion Model™ segments will be used in both sets of analysis.

4.3.8 Deliverables

We will deliver the following to TG:

1. Research study plan.
2. Final report that includes an executive summary, detailed review of findings, with clear and actionable recommendations AND a separate **WHAT IT MEANS** section.
3. The DCM simulator.
4. Cross-tabulation tables.
5. Dataset in SPSS or Excel.
6. Presentation.

4.3.9 Schedule

The following schedule provides a rough timeline for completing this survey.

Project Milestone	Date
Start-up Meeting and Questionnaire Design	2 weeks (starting w/o Oct. 5)
Questionnaire Setup	1 week (starting w/o Oct. 19)
Data Collection	1 week (starting w/o Oct. 26)
Data Cleaning, Coding, Data Processing	2 weeks (starting w/o Nov.2)
Conversion Model™, Regression and DCM Analysis	2 weeks (starting w/o Nov. 16)
Draft Report (delivered by Dec 18, 2010)	3 weeks (starting w/o Nov. 30)
Final Report And Presentation	No Later than Jan. 31, 2010

We will work with TG to make any necessary changes to the proposed timeline upon contract award.

4.4 Price

The price to conduct the study as set out above and within the timeline, with 800 completes is $20,000 + GST or $21,000 Total.

As mentioned, it would be preferable to have more completes. Accordingly, we are providing two other options with larger sample sizes:

- With 1,000 completes, the price is $22,000 + GST or $23,100 Total.
- With 1,200 completes the price is $24,000 + GST or $25,200 Total.

Note that we are charging for extra completes at cost.

4.5 Other Project Management Issues

4.5.1 TG And The BC Utilities Commission

We recognize that to move forward, TG will have to make its case to, and get approval from, the BC Utilities Commission (BCUC). We will work hand-in-hand with TG to ensure that approval is obtained. We are also prepared to make presentations to the BCUC if that is what the Commission requires.

We are familiar with that process as we went through the same procedure with BCTC.

4.5.2 Capacity

At the time of proposal submission, TNS Canadian Facts has the resources and individuals available to undertake this study under the parameters and timeframes outlined in our proposal.

As one of the largest marketing research companies in the world, we have the personnel and resources to quickly and efficiently handle any unforeseen circumstances, and ensure that our commitments to our clients are met. The project at hand requires primarily the resources of a small number of individuals. Should it be necessary, alternate personnel will be available to complete this assignment; our team in Canada includes many senior consultants with experience in the energy sector, including Brook Tyler (Research Director, Toronto) and Moira Silcox (VP, Senior Research Advisor, Vancouver), as well as numerous client service representatives who will assume responsibility for this project if required.

If for any reason, we find that we cannot meet our obligations using our in-house resources, alternative arrangements will be made, and this will be fully disclosed to, and agreed by, TG.

4.5.3 Team Accountability

Members of the project team for this project are all dedicated individuals who take their responsibilities to their clients very seriously. And, we are working in a corporate environment in which we are strongly encouraged to satisfy our clients and fulfill our obligations. Our business depends on this orientation, and we take pride in the service that we provide to our clients. We fully appreciate that future assignments are fully dependent on the good will that we engender with our current clientele.

4.5.4 Issues And Risk Management

TNS Canadian Facts has a comprehensive business interruption plan in place. In the event of a disruptive event, a client service team in another location will be identified, and will draw on back-up files which are stored in secure locations. Should a project team member become unavailable for any reason, another individual, with equal or superior qualifications will be assigned to meet our responsibilities to our clients.

Should a disruptive event adversely impact our Canadian operations, we will draw on our global resources to meet our clients' expectations and our contractual obligations. For example, in the case of an unanticipated event that interrupts our data processing centre, one of our other data processing teams in another country, such as India or Korea, will be called upon to do the data processing.

5.0 Project Team And Qualifications

5.1 Client Service

We value our relationship with Terasen Gas, and demonstrate its importance to us by providing the highest level of competence, responsive service, and bringing creativity and enthusiasm to our work with members of Terasen Gas staff. In addition to being respectful, courteous and professional, we are committed to providing thought leadership, in part, by our thorough understanding of your business issues and the environment in which you operate.

TNS Canadian Facts has a disciplined approach to project management as we believe it is key to ensuring client research needs are met. All projects are designed, analyzed and reported by senior professionals (typically at the vice president or director level). Studies are managed day to day by researchers with a minimum of three years of direct project management experience (typically five years or more) and under the supervision of the senior researcher in charge of the project. Fieldwork and all of the data processing functions are managed by individuals with many years of experience within their highly specialized areas of expertise. TNS Canadian Facts has its own sampling and statistical analysis departments, both of which are managed by our head statistician, a vice president with more than 25 years of experience in applied statistics.

The senior professional client service team members will consult with Terasen Gas researchers to develop a full understanding of the research needs and objectives. This discussion will focus on communications issues and desired business outcomes ***not*** on research issues *per se*. The intention is to design a study firmly grounded to the business case. It is *Smart Research*.

We bring cutting edge and innovative thinking, in part, by our application of our proprietary business solutions. We network internally with our global colleagues to maintain a current knowledge of new research techniques, and do not hesitate to present new ideas to our clients that can contribute to the utility of the research. In many cases we bring our clients together by sharing findings and providing benchmarks for clients who operate in the same sector.

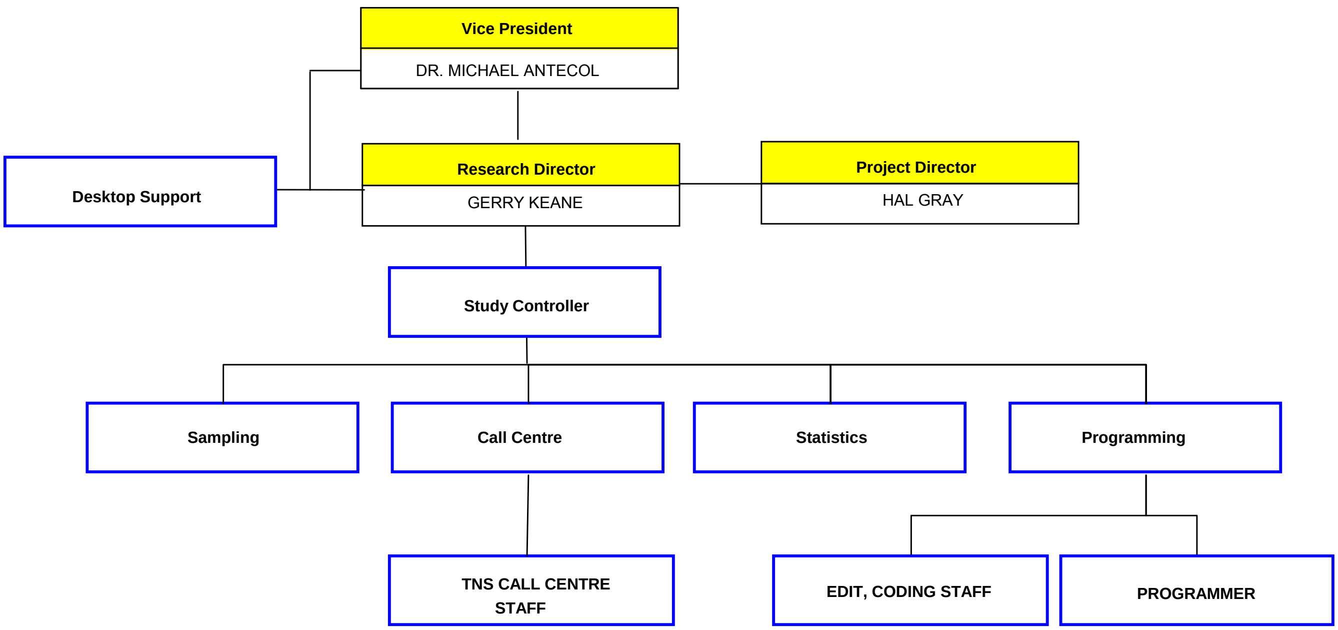
We are fully accountable to our clients for quality and service delivery. The individual team members are committed and dedicated. In the event of unforeseen circumstances, alternate staff members, with equal of better qualifications will be immediately identified and will step in to complete the assignment.

Our commitment to integrity, our vast resources and quality control procedures virtually eliminate service delivery deficiencies. Should this occur, we take immediate steps to rectify the situation to meet both our contractual obligations and to satisfy our client's needs. Our business is built on our reputation, and we distinguish ourselves from our competitors by providing a consistently high standard of work and service.

5.2 Your Project Team

The proposed team for this project is comprised of experienced and committed professionals who will provide outstanding, flexible and innovative consulting services to Terasen Gas in conducting this research. Members of the team have a range of backgrounds, skill-sets and are recognized as leaders in their fields. This, backed by the substantial resources of TNS, will insure full success of the project.

Organizational Chart of the Project Team



To follow are the roles and qualifications of the key members of the project management team.

Dr. Michael Antecol, Vice President, Vancouver

Dr. Michael Antecol will directly oversee this study, with a particular emphasis on design and interpretation.

Vice President of TNS Canadian Facts, and head of its Vancouver office. Michael has both in-depth and practical experience in quantitative and qualitative methodologies and has over 11 years of direct market research experience working with major clients in the US and Canada. A synopsis of Michael's credentials and experience in the marketing research industry is given below.

AT TNS, Michael oversees all activities in the Vancouver office. Prior to joining TNS, Michael was a Vice President at POLLARA (2004-2006), where he focused on media research, particularly local TV news. Other areas of research practice included general TV studies, marketing, social marketing and advertising, young consumers, technology, and telecommunications. Clients included some of Canada's largest companies and major commercial organizations in the western market. *Of particular interest here, Michael oversaw Terasen Gas' residential customer satisfaction research as well as builder satisfaction research. He also oversaw various BC Hydro projects.*

From 2002 to 2004, Michael was Director of Online Research at Frank N. Magid Associates, an international media research company. In combination with traditional telephone research, he applied online methodologies to help clients (such as Belo Corp., Cox Communication, Emmis Broadcasting, and Young Broadcasting in particular) effectively produce local TV news programs. The goal of these studies was to determine consumer attitudes and behaviors to local TV news, understand media consumption habits, develop compelling TV and online content, construct successful marketing and advertising campaigns, driving traffic from local TV newscasts to the station's websites and vice versa, and proof new media concepts. Michael played a critical role in presenting findings to senior management and suggesting recommendations for change. His work is credited for stimulating improved audience ratings for many of his clients.

Michael's studies from his time at Magid have been quoted in various media outlets including Broadcasting & Cable, Christian Science Monitor, MSNBC News, ChronWatch.com, Poynter Online, and the Toronto Star. Some of the research findings have also been presented in speeches to the Bureau of Broadcast Measurement (BBM) Canada and the Television Bureau of Advertising (TVB), and a keynote speech to the predecessor of the Market Research Intelligence Association.

Prior to these appointments, Michael held the position of Young Consumer Analyst at Forrester Research (2000-2002) where he investigated the use of technology in the formulation of marketing strategies directed at young consumers.

In terms of his academic career, Michael completed a B.A. in Political Science at York University and a LL.B. from Osgoode Hall Law School. He then attended the Graduate School of Journalism at the University of Western Ontario where he completed an M.A. in Journalism. He then continued on with his studies and completed a Ph.D. in the School of Journalism at the University of Missouri. Following this, Michael completed a Post-Doctoral Fellowship at Stanford University, receiving independent funding from the California Tobacco-Related Disease Research Program for a project that investigated the effects of advertising as it pertains to anti-smoking campaigns.

Michael's academic research has been widely published in journals such as the Canadian Journal of Communication, Mass Communication & Society, Newspaper Research Journal and Political Communication. Abstracts can be found in various Proceedings of the American Academy of Advertising and Psychophysiology. He has also presented numerous papers to the Association for Education in Journalism and Mass Communication (AEJMC), International Communication Association, the American Academy of Advertising, the Society for Psycho-physiological Research, and the Society for Research on Nicotine and Tobacco. His research has earned several awards including membership in the Kappa Tau Alpha Honor Society and a "Top Three Research Paper" in the Communication and Theory Division of AEJMC.

Michael has also taught graduate-level courses in media research methods at the University of Missouri School of Journalism. He is a member of the Market Research Intelligence Association.

Gerry Keane, Research Director, Vancouver

Gerry will be your key contact working closely with you on this project.

Gerry Keane joined TNS-Canadian Fact recently, complementing his 18 years experience in marketing research. Gerry is and experienced qualitative research who has conducted over 800 focus group and in-depth interviews over his career. He has worked on both client-side and consulting sides but always within marketing research. Prior experience includes program evaluation experience particularly on demand-side management programs for BC Hydro (Power Smart). He also created and oversaw the research program that led to the rebranding of Vancity Savings Credit Union. Gerry also brings extensive experience in brand development and tracking brand awareness. As a skilled project manager, Gerry has a knack for isolating key findings and interpreting them into strategic understanding.

Gerry holds a Bachelor of Arts (Psych.) from the University of Alberta and is a Certified Market Research Professional (CMRP). He is also a member in good standing with the MRIA.

Hal Gray, Project Director, Vancouver

Hal Gray will be responsible for many of the day-to-day tasks involved in the study setup, data collection and data processing of results. He will be project managing the Key Accounts survey.

Hal has worked directly in market research developing project needs analysis and implementation, delivery, monitoring, reporting and evaluation of those projects for the last five years. He has either coordinated or assisted in several longitudinal studies for a social agency, and has directed long-term, quarterly, customer satisfaction studies for major corporations such as a telephone company, and a BC utility. As well, he has coordinated and reported on dozens of custom studies and 50 plus focus groups.

Hal has a background in marketing, promotion and advertising campaigns, events, ideas and programs both in the public and private areas. For many years, Hal held an executive position in the non-profit sector and, as well, a coordinating and teaching position in the post-secondary field.

He has ten years' experience in stakeholder outreach and partnership building in the public and non-profit sectors. Hal has over twenty years experience as a freelance writer and editor in commercial print, audio, video and film and is an award-winning fiction and screenplay writer.

Hal is a member of the Market Research and Intelligence Association. He is a past board member of the Canadian Periodical Publishers Association.

6.0 References

In the following section, we present three (and one alternate) references and case studies to demonstrate our experience in delivering similar projects and providing insightful recommendations.

1. BC Hydro

BC Hydro strives to enhance their approach to measuring the "health of their relationships" with all stakeholders who can materially impact the success of their enterprise. TNS was commissioned to do an annual large-scale tracking customer satisfaction survey for BC Hydro in British Columbia. The reports provided by TNS include the key benchmarks used by the Board of Directors to monitor satisfaction among a population of over 1.5 million customers.

In addition to collecting data and producing the key performance reports, TNS provides analysis and interpretation on a quarterly basis, to assist the company in its customer satisfaction strategy.

Eddie Van Dam
Manager, Research Services
BC Hydro
Tel: (604) 623-4536
e-mail: edward.vandam@bchydro.com

Alternate

TNS conducted a series of focus groups on a new Power Smart initiative. Gerry Keane conducted six focus groups around BC gauging public response to the concept. The discussion followed overall response to the idea as well as generating ideas on how the program would be delivered and promoted.

Shashi Maharaj
Power Smart Evaluator
BC Hydro/Power Smart
Tel : (604) 453-6316
e-mail: eshashi.maharaj@bchydro.com

2. Rogers Plus

Rogers Plus was facing competitive pressures from a direct competitor who aggressively lowered their prices while extending their rental durations on new releases. To understand how the competitors latest offer would impact switching behaviour among movie renters, a market study was undertaken with customers of both chains. A discrete choice modelling analysis was conducted to understand what offerings movie renters value most and how our client should proceed in response to their competition's new offering.

TNS provided a customized share of preference market simulator that Rogers Plus could manipulate the different scenarios to somehow predict the impact on market share of one offering versus another.

Marshal Wilmot
Vice President, Marketing
Rogers Plus
Tel: (604) 644-1027
e-mail: marshall.wilmot@rci.rogers.com

3. British Columbia Transmission Corporation

As a Crown corporation, BCTC's stakeholders include provincial and municipal officials, residents of BC, commercial electricity transmission customers, Independent Power Producers, wholesale electricity providers and industrial customers. BCTC requires an overall view of its stakeholders' impressions along with an understanding of the factors that drive their satisfaction to make operational improvements and introduce initiatives that better meet the needs of its stakeholders. To obtain the views of their stakeholders, BCTC has engaged TNS for the past four years. Multiple data collection methodologies are used, as different channels are more effective with different stakeholder groups.

Key performance metrics collected in this study are reported to the Provincial Government every year. We go as far is rolling these metrics into a single index statistic for BCTC's management team to monitor. Note that this index has been independently audited by KPMG and deemed a valid measure for BCTC's corporate scorecard.

Following this, a roadmap is provided within the research for each stakeholder group. This custom analysis identifies the key priorities BCTC need to address immediately versus longer term. This roadmap is constructed by factoring in BCTC's strengths and weaknesses along with an open multivariate, correlational analyses of what is most important for each stakeholder group.

Nancy Norris
Policy Analyst
BCTC
Tel: (604) 699-7463
e-mail: nancy.norris@bctc.com

7.0 Freedom Of Information And Protection Of Privacy Act

7.1 Overview Of Privacy Compliance

TNS Canadian Facts is a global leader among marketing research firms in compliance with Privacy regulations and legislation within British Columbia, in Canada and in all jurisdictions within which TNS plc operates.

TNS Canadian Facts is proud of its role in leading the marketing research industry on privacy compliance. We were the first survey research firm in Canada to appoint a privacy officer and develop a corporate privacy policy with PIPEDA in mind, more than a year before the law took effect. Our vice president of public affairs, David Stark, chaired a privacy committee of the Marketing Research and Intelligence Association (MRIA) in 2003 and 2004 and he co-authored the association's comprehensive Privacy Protection Handbook. David is also the current president of MRIA.

TNS Canadian Facts is a Gold Seal member of the MRIA, an organization that sets industry standards to which member companies must adhere, and which protect respondents' privacy. Gold Seal members are reviewed biennially for compliance with the MRIA's standards of conduct. An arm's length professional accounting firm with expertise in carrying our quality assurance audits undertakes the standards reviews. In addition, all surveys that we conduct are registered with the MRIA's Survey Registration System. A toll-free telephone number to the MRIA enables respondents to check whether surveys they have been asked to complete are legitimate.

TNS Canadian Facts has implemented numerous practices, policies and procedures to ensure compliance with PIPEDA and protect respondents' privacy:

- Training about PIPEDA's requirements and other privacy laws is conducted regularly with our staff, from interviewers and study controllers to programmers and client service staff.

- Client companies that provide customer lists to our firm for research sample must first enter into a personal information protection agreement (PIPA) with TNS Canadian Facts. Among its many provisions, the agreement gives each party the right to audit the other's information management practices. We have a template PIPA that we use with clients; however, we are happy to review and work with agreements initiated by our clients.

- Before receiving a customer list supplied by a client, we review our client's privacy policy to ensure that it has obtained sufficient consent to be able to disclose its customers' personal information to us.

- Before fieldwork on telephone studies commences, we conduct a thorough briefing with our interviews assigned to the study. We review scripts with them, any privacy considerations, how to respond appropriately to individuals' questions about the survey, and how to handle our clients' unique and specific requirements.

- We maintain our own Do-Not-Contact list of telephone numbers belonging to households who have told us that they do not want to participate in survey research conducted by our firm. We respect individuals' desire not to be contacted without question. All random digit dialling (RDD) and client-supplied samples are screened against our DNC list to ensure that no one is contacted against their wishes.

- We identify ourselves and state the purpose of our contact with prospective survey respondents. For telephone surveys, we proudly display our name and phone number on telephones equipped with caller I.D. When we invite individuals to participate in our surveys, we assure them that their survey responses are treated in strict confidence and that no personally identifiable information is disclosed to other parties.

- For clients who would like to be able to analyze respondent-level data strictly for research purposes, we advocate that a statement to that effect be included in the questionnaire and that we obtain respondents' express permission for the disclosure and use of their survey responses.

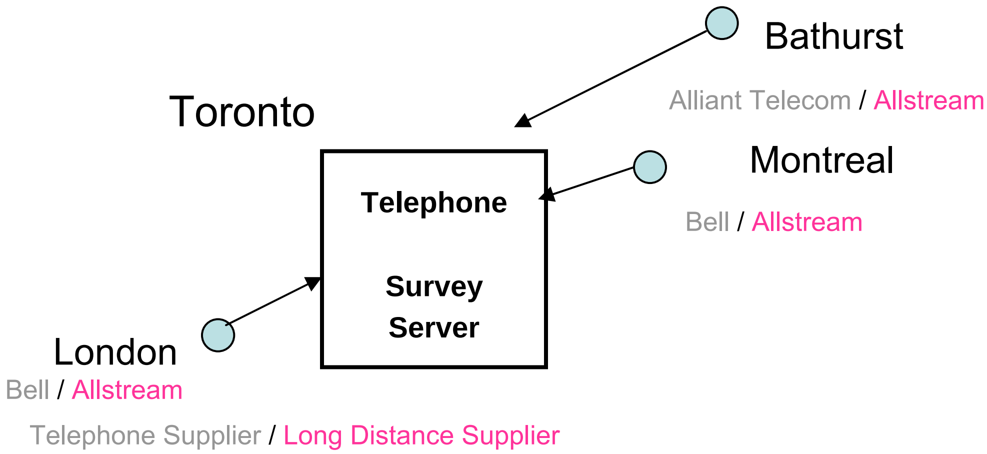
- Identifying information about respondents (i.e., name, address, phone number, etc.) is destroyed as soon as it is no longer needed. The destruction and retention timetable depends on the circumstances of a given project. Longitudinal or tracking studies typically require a longer retention period. In many cases, however, information is kept long enough to allow for the possibility of re-contacting respondents to validate their responses. For most studies, identifying information is destroyed within three months. Many clients require destruction of their customers' contact information immediately upon completion of a study, which we are happy to accommodate.

- We employ technological, physical and organizational security measures to safeguard the personal information we collect, such as the use of firewalls, passwords, controlled-entry into our offices, locks on doors and filing cabinets, and limiting employees' access to personal information on a need-to-know basis. Further, all of our employees are contractually bound to respect client confidentiality and the confidentiality of personal information.

- We are open with our privacy policies and practices. Our privacy policy is accessible from every page on our Web site. Our privacy policy and online data collection practices have been independently reviewed and certified by TRUSTe, an organization that helps consumers and businesses identify trustworthy online organizations through its Web Privacy Seal, Email Privacy Seal and Trusted Download Programs.

7.2 Our Proposed Solution Is Fully Compliant

All aspects of our proposed study design will fully comply with privacy regulations in BC and in Canada. For telephone surveys, call routing will not leave Canada, at any time or for any reason. The details of our telephone interviewing data collection system, and disclosure of our telephone and long distance suppliers are detailed in the diagram following.



Further, all personally identifiable information for surveys conducted via all data collection methodologies remains housed on our servers in Canada, and the data cannot be accessed from outside of Canada. Our servers are housed at our Toronto head office in a locked facility with access limited to those who require it. The server facility is protected by 24-7 building security and CCTV surveillance cameras. We also have a very comprehensive emergency response business continuity and disaster recovery plan in place.

We have reviewed the requirements of FOIPPA with our Privacy Officer and legal counsel. Our solution is fully compliant:

	Yes	**No**
A) Proposed solution is fully compliant with provisions of FOIPPA	☑	
B) Proposed solution requires some modification(s) to comply with the provisions of FOIPPA. (Details as clearly as possible the modifications anticipated, and confirm that all costs associated with those modifications would be borne by the Proponent).		☑
C) Proposed solution is not currently compliant with the FOIPPA and may require significant modifications to comply with the provisions of FOIPPA. (Detail as clearly as possible the modifications anticipated, and confirm that all costs associated with those modifications would be borne by the Proponent).		☑

We are confident an independent evaluation of our solution’s compliance with FOIPPA by Terasen Gas will result in the conclusion that our solution is entirely compliant, and we welcome this review.

Appendix

Our Approach

A DISCRETE CHOICE MODELING EXAMPLE

In this and the following pages, we present a small hotel DCM case study to illustrate the steps that we would apply in using DCM, recognizing that the most important step in the process is to “build” the packages to be tested. The following shows one of the DCM choice screens in the survey:

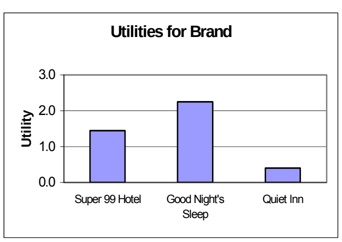
“If you were considering staying at a hotel and these were the only alternatives, which one of the following hotels would you choose to stay in?”

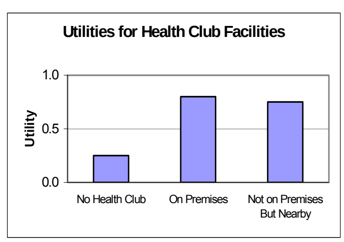
	(1) Super 99 Hotel	(2) Good Night’s Sleep Hotel	(3) Quiet Inn
Price	$90.00 plus taxes	$110.00 plus taxes	$110.00 plus taxes
Location	Near the Airport, Away From Downtown	Downtown	Downtown
Room	Basic Room, Not Cramped But Little Workspace	Large and Spacious with Desk and Table	Large and Spacious with Desk and Table
Health Club Facilities	No Health Club Associated With Hotel	On Premises	Not on Premises But Nearby
Restaurant in Hotel	No, But Restaurants Nearby	Yes	Yes

Additional screens would show different price points and options. Using this approach, DCM has several benefits. It poses a realistic and natural task for the survey respondents. Instead of rating or ranking the choices, the respondent simply makes a purchase decision. Also, packages can be customized to match marketplace reality. Every package does not need to share all of the same attributes or attribute levels. The DCM approach also has the option of allowing respondents to choose a “none” option. By selecting that option, a respondent can contribute information about the decrease in demand to be expected if all of the products are considered unattractive.

Our Approach (cont’d)

After the survey data have been statistically analysed, utility charts can be constructed to show the levels of the attributes that are the most preferred, holding all other attributes constant. The following are examples of utility charts in this hotel case study.





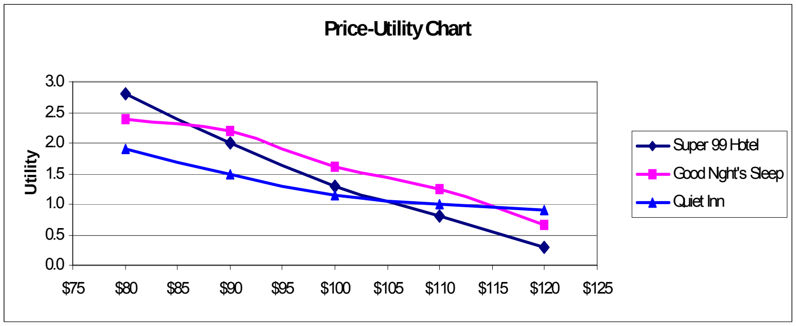
The “brand” utility chart shows that Good Night’s Sleep is the most preferred lodging, followed by Super 99 Hotel. Quiet Inn is the least preferred.

The “health club facilities” chart on the right shows that, when holding all of the other attributes constant, having health care facilities is preferred over having facilities nearby, which is preferred over having no facilities at all. However, the utility difference between having facilities on the premises and nearby is very small, suggesting that consumers place little importance on whether the facilities are on the premises or nearby.

The actual numerical value of the utilities has no meaning; what is important is whether the value is higher or lower than the other utility values on the same chart.

Our Approach (cont'd)

To illustrate the effect of changing one component of the video rental package over another, we use price in our example. The price of the product or service is frequently a major component of any purchase decision. Also, it is erroneous to assume that the "brand" or package type has no effect on price sensitivity. For instance, consumers may be more receptive to a steeper price of a familiar brand than a less popular, even niche brand. DCM has the flexibility to model an individual price utility curve for each brand (or video rental package). Below is an example of a price utility chart.



In this example, the preferred hotel, when all three are at the $80 price point is Super 99 Hotel, followed by Good Night's Sleep and then Quiet Inn. However, there is a different story at the $90 price point - Good Night's Sleep is now the first choice, followed by Super 99 Hotel and then Quiet Inn. If Good Night's Sleep increases to $100, but the other two hotels remain at $90, Super 99 Hotel would then become the most preferred (with a utility value of 2.0). However, Good Night's Sleep would still be preferred over Quiet Inn (the utility of Good Night's Sleep at $100 is about 1.6 and the utility of Quiet Inn at $90 is 1.5). In the analysis, the key is the hotel's utility value in relation to that of the other hotels.

Our Approach (cont'd)

SHARE OF PREFERENCE MARKET SIMULATOR

A share of preference market simulator is used to assess how people's preferences might be affected by changes in package attributes.

In the first scenario, all three hotels are offering rooms at the $90 rate. Super 99 Hotel and Good Night's Sleep have their location attribute set to the Downtown level, and Quiet Inn has the attribute set to the Near the Airport, Away From Downtown level. The rest of the attribute levels are set to the levels desired for this particular marketplace scenario.

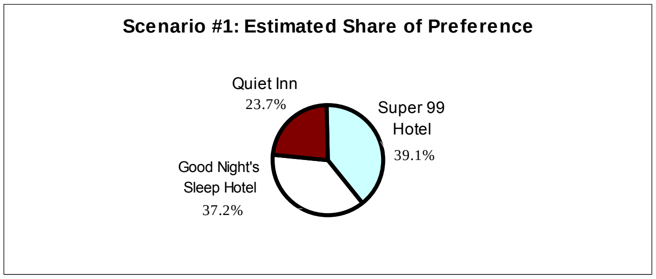
INPUT SCREEN

SCENARIO #1 Inputs

	Super 99 Hotel	Good Night's Sleep Hotel	Quiet Inn
Price	$90.00	$90.00	$90.00
Location	Downtown	Downtown	Near the Airport, Away From Downtown
Room	Basic Room, Not Cramped But Little Workspace	Large and Spacious With Desk and Table	Large and Spacious With Desk and Table
Health Club Facilities	On Premises	Not on Premises But Nearby	No Health Club
Restaurant in Hotel	No, But Restaurants Nearby	No Restaurants in Hotel or Nearby	Yes

Our Approach (cont'd)

Running the market simulator, the output shows that Super 99 Hotel has the largest estimated share of preference among the three hotels at 39.1%, followed by Good Night's Sleep at 37.2% and then Quiet Inn at 23.7%.

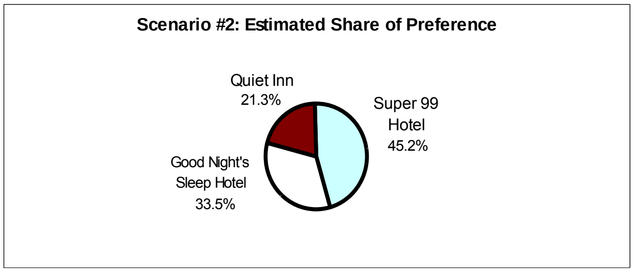


Now, suppose that Super 99 Hotel were considering adding a restaurant to its hotel, but in doing so it would need to increase its room rate …

Our Approach (cont'd)

In Scenario #2, the attribute level for Restaurant in Hotel is changed to Yes and the price is changed to $95. All other attribute levels have been kept the same as in the first case.

Looking at the results of the market simulator below, the restaurant addition and rate increase would be a reasonable course of action. The estimated share of preference among the three hotels in Scenario #2 is Super 99 Hotel at 45.2%, followed by Good Night's Sleep at 33.5% and then Quiet Inn at 21.3%. From these simulations, we can see that, for the Super 99 Hotel, the utility increase associated with the addition of the restaurant outweighs the utility decrease that occurs because of the room rate increase, resulting in a net increase in utility for Super 99 Hotel.



Based on this case study, one can see how new release video rental packages can be similarly tested, how price elasticity can be shown, and how market simulation will give Rogers Video an understanding of the market impact of changing it package parameters. From a data collection and analytical perspective, an Internet based DCM survey is a very powerful research approach.

TERASEN *GREEN GAS* STUDY: Final

INTRODUCTION

DISPLAY1

We are conducting a research study among British Columbia residents about their opinions on environmental issues. Please be assured that this is for research purposes only. It will take approximately 15 minutes of your time.

We would like the person in your household who is fully or jointly responsible for decisions about utility services to complete this survey.

QS1: M, QT

Are you a customer of the following utility companies? (*select all that apply*)

AL

Terasen Gas
BC Hydro
TELUS
None

QS2: S, QT

Do you or does any member of your household work for an energy utility, a gas marketer, or a public media, advertising, public relations or market research company?

AL

Yes
No

INSTRUCTION:
IF QS2 IS (NO) CONTINUE, ELSE TERMINATE

MARKET DRIVERS

QM1: M, QT

How concerned are you about…?

AL

10 – Very Concerned
9
8
7
6
5
4
3
2
1 – Not At All Concerned
Decline

MT

RANDOMIZE

The current state of the environment
The future state of the environment
The effects of global warming /climate change
Greenhouse gas emissions
The loss of oxygen producing forests
The level of government or industry leadership on environmental issues
Access to alternative energy solutions

ENERGY USE / GREEN PRODUCTS IN THE HOME			
QG1: S, QT	Have you taken steps to save energy in your home?	
AL	Yes No Don't know Decline	
	INSTRUCTIONS: IF QG1 IS (YES) CONTINUE IF QG1 IS (NO) GO TO QG3, ELSE GO TO NEXT SECTION	
QG2: M, QT	What steps have you taken to save energy in your home? (*select all that apply*)	
AL	Reduced water use (e.g. low flow showerheads) Energy efficient lighting Installed timers for lighting Installed a programmable thermostat Weather stripping / caulking Insulating windows / doors / spaces Re-using / reducing / recycling materials Replaced existing furnace with a high-efficiency furnace Alternative energy sources (e.g. heat pumps, solar panels) Other (Specify)	RANDOMIZE
QG3: OPEN, QT	Why have you not taken steps to save energy in the home?	
AL	RECORD ANSWER Decline	

COMMITMENT

QCM1: M, QT

We know that different people have different lifestyles. For the following three types of lifestyles, what is your general **impression** of each one?

Please choose a number from 1 to 10, where '10' means you feel extremely positive and '1' means you feel extremely negative about that type of lifestyle.
(*select one for each*)

AL

10 – Extremely positive
9
8
7
6
5
4
3
2
1 – Extremely negative

MT

A lifestyle in which you consider the environmental impact of almost everything you do.
A lifestyle in which you consider the environment impact when it is reasonable or practical to do so.
A lifestyle where you do not consider the environmental impact of anything you do.

QCM2: S, QT

Now thinking about your own day-to-day lifestyle, which of the following best describes your current lifestyle. *(select one only)*

AL

A lifestyle in which you consider the environmental impact in almost everything you do.
A lifestyle in which you consider the environment impact when it is reasonable or practical to do so.
A lifestyle where you do not consider the environmental impact in anything you do.

QCM3: S, QT

Some things are extremely important and are worth thinking about, while others don't require much thought at all. Thinking about the different lifestyles that we have been discussing, how important is this decision in your life? (*select one only)*

AL

Extremely Important
Very Important
Moderately Important
Slightly Important
Not At All Important

QCM4: S, QT

Thinking now about your current lifestyle, to what extent can you think of reasons to continue with this lifestyle? (*select one only)*

AL

There are many good reasons to continue with your current lifestyle in relation to environmental choices and no reason to change.
There are many good reasons to continue with your current lifestyle in relation to environmental choices, but also many good reasons to change.
There are few good reasons to continue with your current lifestyle in relation to environmental choices and many reasons to change.

TERASEN GAS

QT1: M, QT

Terasen Gas is the primary natural gas provider in British Columbia. From your direct experience with the company, and from what you have heard, seen or read, on a scale from 1 to 10, where '10' means you feel Terasen is excellent and '1' means you feel Terasen is poor, how would you rate Terasen Gas in terms of being a company that cares about…?

PRE-MEASURE

AL

10 – Excellent
9
8
7
6
5
4
3
2
1 – Poor
Not relevant to me
Decline

MT

Its employees
Its role in the community
The environment
Making a profit
Re-investing in new environmentally-friendly technologies

RANDOMIZE

DISPLAY2

Terasen Gas is investing in a number of projects to collect methane gas produced from landfills, waste water treatment plants, animal manure and organic waste with the intention of delivering pipeline-quality gas to consumers.

By capturing, cleaning and delivering methane to the market that would otherwise be released to atmosphere; significant greenhouse gas reductions are achieved. We refer to this renewable gas as biogas.

Terasen hopes that by offering a biogas program, where customers can sign up for a portion of their energy use to be supplied from biogas, biogas can become a viable, renewable energy source for our region.

QT2: S, QT

Do you think Terasen Gas should be investing in biogas projects?

AL

10 – Definitely
9
8
7
6
5
4
3
2
1 – Definitely not
Decline

QT3: S, QT

Do you think Terasen Gas should invest in offering a biogas program to its residential customers?

AL

10 – Definitely
9
8
7
6
5

	4 3 2 1 – Definitely not Decline	
QT4: S, QT	All things being equal, if Terasen Gas offered a biogas program, how likely would you be to sign up?	
AL	10 – Very Likely 9 8 7 6 5 4 3 2 1 – Not Very Likely Decline	
	INSTRUCTION: IF QT4 IS (7-10) CONTINUE ELSE GO TO QP1A	
QT5: M, QT	What, if any, would be your motivation for signing up for such a program? (*select all that apply*)	
AL	Promoting new technologies Providing for future generations Preserving nature Human health Doing the right thing Status in your peer group Being on the cutting edge Supporting local farmers by providing income for their waste streams Supporting local developments Other (Specify) Don’t know	RANDOMIZE
QT6: S, QT	And what would be your *most* important motivation for signing up for such a program? (*select one only*)	
AL	Promoting new technologies Providing for future generations Preserving nature Human health Doing the right thing Status in your peer group Being on the cutting edge Supporting local farmers by providing income for their waste stream Supporting local developments Other (Specify) Don’t know	RANDOMIZE

PRICE FOR BIOGAS

QP1: S, QT

The costs for a biogas program can be offered to consumers in one of two ways. Which way would you prefer to see Terasen offer this program, if it were to do so? *(select one only)*

AL

Terasen offers a biogas program for its customers to sign up for. Those who sign up would pay a premium for biogas.

The increase in cost for biogas supply would be borne by all Terasen Gas customers.

Don't know

INSTRUCTIONS:

SPLIT SAMPLE IN THIRD, INTO SAMPLE A, SAMPLE B AND SAMPLE C

IF SAMPLE A, ASK QP1A

IF SAMPLE B, GO TO QP2A

IF SAMPLE C, GO TO QP3A

INSTRUCTION:
IF QT3 IS (4-10) CONTINUE, ELSE GO TO QC1

QP1A: S, QT

If the cost of biogas is borne by all customers and you had to pay 3% more than the current commodity price of natural gas—which is about $1.80 more than the current monthly charge—would you or would you not support such a biogas program?

AL

Yes, would support program

No, would not support program

Don't know

INSTRUCTIONS:

IF QP1A IS (NO) OR (DON'T KNOW) CONTINUE, ELSE GO TO QC1

QP1B: S, QT

If the cost of biogas is borne by all customers and you had to pay 2% more than the current commodity price of natural gas—which is about $1.20 more than the current monthly charge—would you or would you not support such a biogas program?

AL

Yes, would support program

No, would not support program

Don't know

INSTRUCTIONS:

IF SAMPLE B CONTINUE, ELSE GO TO QC1

QP2A: S, QT

If the cost of biogas is borne by all customers and you had to pay 2% more than the current commodity price of natural gas—which is about $1.20 more than the current monthly charge—would you or would you not support such a biogas program?

AL

Yes, would support program

No, would not support program

Don't know

INSTRUCTIONS:

IF QP2A (NO) OR (DK) CONTINUE, ELSE GO TO QC1

QP2B: S, QT

If the cost of biogas is borne by all customers and you had to pay 1% more than the current commodity price of natural gas—which is about $0.60 more than the current monthly charge—would you or would you not support such a biogas program?

AL

Yes, would support program

No, would not support program

Don't know

INSTRUCTIONS:
IF SAMPLE C CONTINUE, ELSE GO TO QC1

QP3A: S, QT

If the cost of biogas is borne by all customers and you had to pay 1% more than the current commodity price of natural gas—which is about $0.60 more than the current monthly charge—would you or would you not support such a biogas program?

AL

Yes, would support program
No, would not support program
Don't know

INSTRUCTIONS:
IF QP3A (NO) OR (DK) CONTINUE, ELSE GO TO QC1

QP3B: S, QT

If the cost of biogas is borne by all customers and you had to pay 0.5% more than the current commodity price of natural gas—which is about $0.30 more than the current monthly charge–would you or would you not support such a biogas program?

AL

Yes, would support program
No, would not support program
Don't know

CARBON OFFSETS

QC1: S, QT

Have you heard of the term '**carbon offset'**?

AL

Yes
No
Not Sure

DISPLAY3

A **carbon offset** is what a buyer (you) receives in exchange for supporting a project that reduces greenhouse gases in the environment.

The buyer benefits because their purchase of a carbon offset balances out greenhouse gases released by the buyer's activities, such as home heating and cooling, driving a car or manufacturing.

The organization selling the **carbon offset** benefits because it makes offset projects more economically viable over time.

Offset projects range from planting trees—which absorb carbon dioxide from the atmosphere—to sophisticated renewable energy such as landfill methane capture and clean-up and high-efficiency equipment projects.

QC2: S, QT

Knowing this information, how likely would you be to purchase a **carbon offset** for your personal natural gas use in order to reduce your individual environmental footprint? *(select one only)*

AL

Already purchasing one
10 - Extremely likely
9
8
7
6
5
4
3
2
1 - Not at all likely
Need more information

ASK IF QC2 = 8/9/10, ELSE SKIP TO QC4

QC3: M, QT

Carbon offsets are sold through a number of sources. Would you prefer to purchase an offset through… *(select all that apply)*

AL

Your local utility provider
A 3rd party provider that supports projects in BC
A 3rd party provider that supports projects outside BC
Need more information / Don't know

DISPLAY4

There are potentially two types of pricing programs utilities could offer in relation to reducing residential environmental footprints – offset programs or renewable energy programs.

Offset programs – customers are offered the option to offset their home natural gas use by purchasing carbon offsets through the utility.

Most utility companies selling carbon offsets have criteria around which offsets will be purchased, e.g., their own renewable energy projects and / or third party biogas, wind projects or solar projects within their service territory.

Renewable energy programs – customers pay a premium for a portion of their natural gas to be supplied only from utility invested renewable energy projects such as biogas.

QC4: S, QT	Which of these two programs would you be more inclined to see Terasen Gas introduce, if it were to do so? *(select one only)*	
AL	Offset program Renewable energy program Neither Don't know	
	ASK ALL	
QC5: M, QT	What types of offset projects would you want to see Terasen Gas invest in outside of its own renewable energy projects? *(select all that apply)*	RANDOMIZE
AL	Solar Power - Generate energy from sunlight. Geothermal Power – energy extracted from the ground for heating. Wind Power - Use wind to create electricity. Fuel Efficiency - Burn a particular fuel more efficiently. Fuel Substitution - Switch to a fuel that emits less carbon such as diesel trucks to natural gas trucks. Efficient Lighting - Replace light bulbs with fluorescent lamps. Heat-Electricity Cogeneration - Create electricity and heat together. Energy from Biomass - Burn wood waste to generate electricity. Forestation - Plant trees which absorb carbon dioxide. Environmental Buildings - Make buildings more energy efficient. 3rd Party Biogas Projects – within BC 3rd Party Biogas Projects – outside BC Public Transportation - Subsidize or encourage the use of public transport. No preference None of the Above	

NATURAL GAS CHOICES

ASK QN1 IF QT2 = 4/5/6/7/8/9/10, ELSE SKIP TO QN3

ONLY ASKED IF INTERESTED IN BIOGAS PROGRAM

DISPLAY5

In the following section, you will be presented with several screens showing options for energy initiatives. Regardless of whether you would enrol in such a program, imagine your preference amongst the following choices.

Although some of the options will look similar from screen to screen, please pay attention to the details, as each screen is unique.

Please note the following definitions.

Renewable Energy Program:

The price premium paid would result in a portion of the customer's natural gas use being supplied from biogas and would contribute to making biogas become a more viable, renewable energy source for the region.

Carbon Offset Program:

The price premium paid by the customer would go towards purchasing offsets from utility invested biogas projects, as well as from other carbon offset projects and would contribute to offsetting greenhouse gases from a customer's natural gas use.

INSTRUCTIONS:

EACH SCREEN WILL INCLUDE TWO DIFFERENT CHOICES WITH TEXT TO DESCRIBE THE FEATURES IN EACH CHOICE SET. RESPONDENTS WILL SELECT THE OPTION THAT APPEALS TO THEM OR NEITHER OF THE CHOICES.

QN1: M, QT

If you were asked to support one of the following two choices from Terasen Gas, which option would you be the most likely to choose?

PAIR ALL COMBINATIONS OF LEVELS. ONE SCREEN PER PAIRING.

RANDOMIZE ORDER OF PAIRINGS

LEVELS

Energy initiative:

Renewable Energy Program

Carbon Offset Program

Percent Reduction In Your Green House Gas Emissions:

10 %

20%

30 %

50%

80%

100%

Effect On Monthly Gas Bill:

The current commodity price + 10% (about extra $6/month)

The current commodity price + 20% (about extra $12/month)

The current commodity price + 30% (about extra $18/month)

QN3: S, QT

Assuming Terasen Gas could develop and offer a renewable biogas program like the one we've been asking you about, how would you then rate Terasen Gas in terms of being a company that cares about…?

POST-MEASURE

AL

10 – Excellent

9

8

7

6

5

4

	3 2 1 – Poor Not relevant to me Decline	
MT	Its employees Its role in the community The environment Making a profit Re-investing in new environmentally-friendly technologies	RANDOMIZE

DEMOGRAPHICS

QD1: S, QT	Do you receive your gas bill directly from Terasen Gas or do you pay for your gas indirectly (e.g., through your rent payment, strata fees, etc)? (*select one only)*	
AL	Receive bill directly from Terasen Gas Pay gas bill indirectly Does not use gas Don't know	
QD2: M, QT	Which of the following natural gas appliances, if any, do you have in your home? (*select one for each*)	
AL	Yes No Don't know	
MT	Natural gas furnace Natural gas hot water heater that heats your tap water Natural gas boiler for home heating Natural gas range, cook top, or oven Natural gas fireplace Natural gas clothes dryer Natural gas barbecue that uses the gas service from your home Other natural gas appliances (SPECIFY)	
D3: S, QT	What is the <u>main</u> space heating fuel type in your home? (*select one only)*	
AL	Natural gas Electricity Piped propane Bottled propane Oil Wood OTHER Don't know / Not sure	
D5: S, QT	Are you a homeowner or renter? (*select one only)*	
AL	Homeowner Renter Decline	
D6: S, QT	What type of dwelling do you live in? (*select one only)*	

AL	Single-Detached house Apartment Building / Condo Row House / Townhouse / Condo Development Duplex / Triplex Suite contained within a house Mobile or Manufactured home Don't know / Decline
D7: S, QT	In what area of BC do you live?
AL	Lower Mainland Whistler Interior Vancouver Island Sunshine Coast Decline

QUESTIONS THAT WILL NOT BE ASKED, BUT COLLECTED THRU OUR PANEL STATS

PANEL: S,
QT

Into which of the following age categories do you fall? (*select one only)*

AL

18 to 24 years
25 to 34 years
35 to 44 years
45 to 54 years
55 to 64 years
65 years or more
Decline

PANEL: S,
QT

Including yourself, how many people live in your household?

AL

One
Two
Three
Four
Five
Six
Seven or more
Decline

PANEL: S,
QT

Are there any children 18 years of age or under in the household? (*select one only)*

AL

Yes
No
Decline

PANEL: S,
QT

What is the highest level of education that you have attained? (*select one only)*

AL

Public or elementary school
Secondary or high school
Technical or Cegep college
Community college
University
Post Graduate
Other

PANEL: S,
QT

Which of the following best describes your household's 2008 total income before taxes? (*select one only)*

AL

Less than $15,000
$15,000 to less than $25,000
$25,000 to less than $35,000
$35,000 to less than $45,000
$45,000 to less than $60,000
$60,000 to less than $80,000
$80,000 to less than $100,000
$100,000 or more
Don’t know / Decline

PANEL: S,
QT

Are you…*[NOT ASKED – WILL GET INFO FROM PANEL]*

AL

Male
Female

DISPLAY	Thank you very much for participating in this survey. All information provided by you will be held in strictest confidence and will only be used for research purposes.

TERASEN *GREEN GAS COMMERCIAL* STUDY: TELEPHONE SCREENER Final

INTRODUCTION

DISPLAY1

Hello, my name is ___________ from TNS Canadian Facts. We are conducting a research study among British Columbia business leaders and organization decision-makers about their opinions on environmental issues. Please be assured that this is for research purposes only. We need just three minutes of your time, but first we need to ask:

QS1: S, QT

Is the company you represent an energy utility, a gas marketer, or a public media, advertising, public relations or market research company?

AL

Yes
No

INSTRUCTION:
IF QS1 IS (NO) CONTINUE, ELSE TERMINATE

We would like to talk to the person in your organization who is a chief or joint decision-maker concerning administrative or energy matters.

INTERVIEWER NOTE: SCREEN UNTIL YOU FIND THE APPROPRIATE INDIVIDUAL

QS2: M, QT

On a scale of 1 to 10 with ‘1’ being ‘not at all concerned’ and ‘10’ being ‘very concerned’, how concerned are you about the following environmental issues and their effect on your company…?

AL

10 – Very Concerned
9
8
7
6
5
4
3
2
1 – Not At All Concerned
Decline

MT

RANDOMIZE

The current state of the environment
The future state of the environment
The effects of global warming / climate change
Greenhouse gas emissions
Greenhouse gas regulations
The loss of oxygen producing forests
The level of government or industry leadership on environmental issues
Access to alternative energy solutions

QS3: S,

QT	Terasen Gas is interested in your valued opinion about how new sources of alternative energy could influence business attitudes and decisions. Representatives of businesses and organizations who complete the survey can choose to enter a prize draw for $500. The winner can also choose to donate this sum to a charity of their choice. Would you be willing to participate in a 20-minute online survey that goes into these topics more broadly?
AL	YES – CONTINUE NO – THANK AND TERMINATE DON'T KNOW – THANK AND TERMINATE
QS4: S, QT	Could we please have your email address? It will be used exclusively for the mentioned research project and will not be distributed or used for any other reason. Your survey answers will be held in strictest confidence and not be individually identified, but will be aggregated with all other returns.
AL	RECORD E-MAIL ADDRESS: ________________________ I do not want to disclose my e-mail address RECORD FIRST NAME ONLY (Optional): ________________________ I do not want to disclose my name INSTRUCTION: IF E-MAIL ADDRESS GIVEN, CONTINUE ELSE GO TO CLOSING.
DISPLAY2	Thank you. Within the next couple of days, we will be sending you an e-mail with a link to the survey and a unique id and password to enter the survey.

TERASEN *GREEN GAS COMMERCIAL* STUDY: Final

INTRODUCTION

DISPLAY1

We are conducting a research study with British Columbia organizations about their opinions on environmental issues. Please be assured that this is for research purposes only. It will take approximately 20 minutes of your time.

Thank you for agreeing to be a part of this important study.

ENERGY USE / GREEN PRODUCTS IN THE ORGANIZATION

QG1: S, QT

Has your organization taken steps to save energy at its location(s)?

AL

Yes
No
Don't know
Decline

INSTRUCTIONS:
IF QG1 IS (YES) CONTINUE
IF QG1 IS (NO) GO TO QG3, ELSE GO TO NEXT SECTION

QG2: M, QT

What steps have been taken to save energy in your organization? (*select all that apply*)

AL

RANDOMIZE

Reduced water use (e.g., aerators, water-conserving faucets)
Energy efficient lighting
Installed timers for lighting
Installed a programmable thermostat
Weather stripping / caulking
Insulating windows / doors / spaces
Replaced windows / doors with energy efficient windows / doors
Re-using / reducing / recycling materials
Replaced existing space heating equipment with high-efficiency upgrades
Installed a high-efficiency water heater
Alternative energy sources (e.g., heat pumps, solar panels)
Conducted energy saving awareness program with employees
Other (Specify)

QG3: OPEN, QT

Why has your organization not taken steps to save energy?

AL

RECORD ANSWER
Decline

COMMITMENT

QCM1: M, QT

We know that organizations adopt different practices. For the following three types of business practices, what is your general **impression** of each one?

Please choose a number from 1 to 10, where '10' means you feel extremely positive and '1' means you feel extremely negative about that type of practice.
(*select one for each*)

AL

10 – Extremely positive
9
8
7
6
5
4
3
2
1 – Extremely negative

MT

A business practice in which the organization considers the environmental impact of almost everything it does.

A business practice in which the organization considers the environmental impact when it is reasonable or practical to do so.

A business practice where the organization does not consider the environmental impact of anything it does.

QCM2: S, QT

Now thinking about your organization's business practices, which of the following best describe its current philosophy. *(select one only)*

AL

Your organization considers the environmental impact in almost everything it does.

Your organization considers the environmental impact when it is reasonable or practical to do so.

Your organization does not consider the environmental impact in anything it does.

QCM3: S, QT

Some things are extremely important and are worth thinking about, while others don't require much thought at all. Thinking about the different business practices that we have been discussing, how important are they for your organization? (*select one only)*

AL

Extremely Important
Very Important
Moderately Important
Slightly Important
Not At All Important

QCM4: S, QT

Thinking now about your current business practices, to what extent can you think of reasons to continue with this practice? (*select one only)*

AL

There are many good reasons to continue with your current business practices in relation to environmental choices and no reason to change.

There are many good reasons to continue with your current business practices in relation to environmental choices, but also many good reasons to change.

There are few good reasons to continue with your current business practices in relation to environmental choices and many reasons to change.

TERASEN GAS

QT1: M, QT

Terasen Gas is the primary natural gas provider in British Columbia. From your organization's direct experience with Terasen, and from what you have heard, seen or read, on a scale from 1 to 10, where '10' means you feel Terasen is excellent and '1' means you feel Terasen is poor, how would you rate Terasen Gas in terms of being a company that cares about…? (*select one for each*) — PRE-MEASURE

AL

10 – Excellent
9
8
7
6
5
4
3
2
1 – Poor
Not relevant to me
Decline

MT — RANDOMIZE

Its employees
Its role in the community
The environment
Making a profit
Re-investing in new environmentally-friendly technologies

DISPLAY2

Terasen Gas is investing in a number of projects to collect methane gas produced from landfills, waste water treatment plants, animal manure and organic waste with the intention of delivering pipeline-quality gas to consumers.

By capturing, cleaning and delivering methane to the market that would otherwise be released to atmosphere, significant greenhouse gas reductions are achieved. We refer to this renewable gas as biogas.

Terasen hopes that by offering a biogas program, where customers can sign up for a portion of their energy use to be supplied from biogas, biogas can become a viable, renewable energy source for our region.

QT2: S, QT

Does your organization support Terasen Gas investing in biogas projects?
(select one only)

AL

10 – Definitely
9
8
7
6
5
4
3
2
1 – Definitely not
Decline

QT3: S,

QT	Do you think Terasen Gas should invest in offering a biogas program to its commercial customers? *(select one only)*	
AL	10 – Definitely 9 8 7 6 5 4 3 2 1 – Definitely not Decline	
QT4: S, QT	All things being equal, if Terasen Gas offered a biogas program, how likely would your organization be to sign up? *(select one only)*	
AL	10 – Very Likely 9 8 7 6 5 4 3 2 1 – Not Very Likely Decline INSTRUCTION: IF QT4 IS (7-10) CONTINUE ELSE GO TO QP1A	
QT5: M, QT	What, if any, would be the motivation for your organization to sign up for such a program? (*select all that apply*)	
AL	Promoting new technologies Providing for future generations Preserving nature Human health Doing the right thing Status in your peer group Being on the cutting edge Supporting local farmers by providing income for their waste streams Supporting local developments Meeting government greenhouse gas regulations Meeting corporate environmental initiatives Corporate image Other (Specify) Don't know	RANDOMIZE
QT6: S, QT	And what would be your organization's **most** important motivation for signing up for such a program? (*select one only*)	
AL	Promoting new technologies Providing for future generations Preserving nature Human health	RANDOMIZE

Doing the right thing
Status in your peer group
Being on the cutting edge
Supporting local farmers by providing income for their waste stream
Supporting local developments
Meeting government greenhouse gas regulations
Meeting corporate environmental initiatives
Corporate image
Other (Specify)
Don't know

PRICE FOR BIOGAS

QP1: S, QT

The costs for a biogas program can be offered to consumers in one of two ways. Which way would you prefer to see Terasen offer this program, if it were to do so? *(select one only)*

AL

Terasen Gas offers a biogas program that its customers can sign up for. Those who sign up would pay a premium for biogas.

The increase in cost for biogas supply would be borne by all Terasen Gas customers.

Don't know

INSTRUCTIONS:

SPLIT SAMPLE IN THIRD, INTO SAMPLE A, SAMPLE B AND SAMPLE C

IF SAMPLE A, ASK QP1A

IF SAMPLE B, GO TO QP2A

IF SAMPLE C, GO TO QP3A

INSTRUCTIONS:
IF QT3 IS (4-10) CONTINUE, ELSE GO TO QC1

QP1A: S, QT

If the cost of biogas is borne by all customers and your organization had to pay 3% more than the current commodity price of natural gas—which is about $0.20 more per Gigajoule (GJ)—would your organization or would your organization not support such a biogas program?

AL

Yes, it would support program

No, it would not support program

Don't know

INSTRUCTIONS:

IF QP1A IS (NO) OR (DON'T KNOW) CONTINUE, ELSE GO TO QC1

QP1B: S, QT

If the cost of biogas is borne by all customers and your organization had to pay 2% more than the current commodity price of natural gas—which is about $0.13 more per GJ—would your organization or would your organization not support such a biogas program?

AL

Yes, it would support program

No, it would not support program

Don't know

INSTRUCTIONS:

IF SAMPLE B CONTINUE, ELSE GO TO QC1

QP2A: S, QT

If the cost of biogas is borne by all customers and your organization had to pay 2% more than the current commodity price of natural gas—which is about $0.13 more per Gigajoule (GJ)—would your organization or would your organization not support such a biogas program?

AL

Yes, it would support program

No, it would not support program

Don't know

INSTRUCTIONS:

IF QP2A (NO) OR (DK) CONTINUE, ELSE GO TO QC1

QP2B: S,

QT

If the cost of biogas is borne by all customers and your organization had to pay 1% more than the current commodity price of natural gas—which is about $0.07 more per GJ—would your organization or would your organization not support such a biogas program?

AL

Yes, it would support program
No, it would not support program
Don't know

INSTRUCTIONS:
IF SAMPLE C CONTINUE, ELSE GO TO QC1

QP3A: S, QT

If the cost of biogas is borne by all customers and your organization had to pay 1% more than the current commodity price of natural gas—which is about $0.07 more per Gigajoule (GJ)—would your organization or would your organization not support such a biogas program?

AL

Yes, it would support program
No, it would not support program
Don't know

INSTRUCTIONS:
IF QP3A (NO) OR (DK) CONTINUE, ELSE GO TO QC1

QP3B: S, QT

If the cost of biogas is borne by all customers and your organization had to pay 0.5% more than the current commodity price of natural gas—which is about $0.04 more per GJ–would your organization or would your organization not support such a biogas program?

AL

Yes, it would support program
No, it would not support program
Don't know

CARBON OFFSETS

QC1: S, QT

Have you heard of the term '**carbon offset'**?

AL

Yes
No
Not Sure

DISPLAY3

A **carbon offset** is what a buyer (your organization) receives in exchange for supporting a project that reduces greenhouse gases in the environment.

The buyer benefits because their purchase of a carbon offset balances out greenhouse gases released by the buyer's activities, such as heating and cooling, transportation activities or manufacturing.

The organization selling the **carbon offset** benefits because it makes offset projects more economically viable over time.

Offset projects range from planting trees—which absorb carbon dioxide from the atmosphere—to sophisticated renewable energy such as landfill methane capture and clean-up and high-efficiency equipment projects.

QC2: S, QT

Knowing this information, how likely would your organization be to purchase a **carbon offset** for its natural gas use in order to reduce your organization's environmental footprint? *(select one only)*

AL

Already purchasing one
10 - Extremely likely
9
8
7
6
5
4
3
2
1 - Not at all likely
Need more information

ASK IF QC2 = 8/9/10, ELSE SKIP TO QC4

QC3: M, QT

Carbon offsets are sold through a number of sources. Would your organization prefer to purchase an offset through…? *(select all that apply)*

AL

Your local utility provider
A 3rd party provider that supports projects in BC
A 3rd party provider that supports projects outside BC
Need more information / Don't know

DISPLAY4	There are potentially two types of pricing programs utilities could offer in relation to reducing customers' environmental footprints – offset programs or renewable energy programs. **Offset programs** – customers are offered the option to offset their organization's natural gas use by purchasing carbon offsets through the utility. Most utility companies selling carbon offsets have criteria around which offsets will be purchased, e.g., their own renewable energy projects and / or third party biogas, wind projects or solar projects within their service territory. **Renewable energy programs** – customers pay a premium for a portion of their natural gas to be supplied only from utility invested renewable energy projects such as biogas.	
QC4: S, QT	Which of these two programs would your organization be more inclined to see Terasen Gas introduce, if it were to do so? *(select one only)*	
AL	Offset program Renewable energy program Neither Don't know	
	INSTRUCTION: ASK ALL	
QC5: M, QT	What types of offset projects would your organization want to see Terasen Gas invest in outside of its own renewable energy projects? *(select all that apply)*	RANDOMIZE
AL	Solar Power - Generate energy from sunlight. Geothermal Power – Extract energy from the ground for heating. Wind Power - Use wind to create electricity. Fuel Efficiency - Burn a particular fuel more efficiently. Fuel Substitution - Switch to a fuel that emits less carbon such as diesel trucks to natural gas trucks. Efficient Lighting - Replace light bulbs with fluorescent lamps. Heat-Electricity Cogeneration - Create electricity and heat together. Energy from Biomass - Burn wood waste to generate electricity. Forestation - Plant trees which absorb carbon dioxide. Environmental Buildings - Make buildings more energy efficient. 3rd Party Biogas Projects – within BC 3rd Party Biogas Projects – outside BC Public Transportation - Subsidize or encourage the use of public transport. No preference None of the Above	

NATURAL GAS CHOICES

ASK QN1 IF QT2 = 4/5/6/7/8/9/10, ELSE SKIP TO QN65

ONLY ASKED IF INTERESTED IN BIOGAS PROGRAM

DISPLAY5

In the following section, you will be presented with several screens showing options for energy initiatives. Regardless of whether your organization would enrol in such a program, imagine your preference amongst the following choices.

Although some of the options will look similar from screen to screen, please pay attention to the details, as each screen is unique.

Please note the following definitions.

Renewable Energy Program:

The price premium paid would result in a portion of the customer's natural gas use being supplied from biogas and would contribute to making biogas become a more viable, renewable energy source for the region.

Carbon Offset Program:

The price premium paid by the customer would go towards purchasing offsets from utility invested biogas projects, as well as from other carbon offset projects and would contribute to offsetting greenhouse gases from a customer's natural gas use.

INSTRUCTIONS:

EACH SCREEN WILL INCLUDE TWO DIFFERENT CHOICES WITH TEXT TO DESCRIBE THE FEATURES IN EACH CHOICE SET. RESPONDENTS WILL SELECT THE OPTION THAT APPEALS TO THEM OR NEITHER OF THE CHOICES.

QN1: M, QT

If your organization was asked to support one of the following two choices from Terasen Gas, which option would it be the most likely to choose?

PAIR ALL COMBINATIONS OF LEVELS. ONE SCREEN PER PAIRING.

RANDOMIZE ORDER OF PAIRINGS

LEVELS

Energy initiatives:

Renewable Energy Program

Carbon Offset Program

Percent Reduction In Your Green House Gas Emissions:

10 %

20%

30 %

50%

80%

100%

Effect On Monthly Gas Bill:

The current commodity price + 10% (about extra $0.65/GJ)

The current commodity price + 20% (about extra $1.30/GJ)

The current commodity price + 30% (about extra $1.95/GJ)

QN65: S, QT

Assuming Terasen Gas could develop and offer a renewable biogas program like the one we've been asking you about, how would you then rate Terasen Gas in terms of being a company that cares about…?
(select one for each)

POST-MEASURE

AL

10 – Excellent

9

8

7

	6 5 4 3 2 1 – Poor Not relevant to me Decline	
MT	Its employees Its role in the community The environment Making a profit Re-investing in new environmentally-friendly technologies	RANDOMIZE

DEMOGRAPHICS

QD1: S, QT	What sector is your organization in? (*select one only)*	
AL	Retail Government Organization Office Hospitality Auto Repair / Gas Station Construction Agriculture Food Recreation Institutional Industrial Wood & Forest Commercial Don't know / Decline	
D2: S, QT	What is the <u>main</u> space heating fuel type in your organization? (*select one only)*	
AL	Natural gas Electricity Piped propane Bottled propane Oil Wood OTHER Don't know / Not sure	
D3: S, QT	Are you a business owner or an employee? (*select one only)*	
AL	Owner Employee Decline	
D4: S, QT	In what area of BC is your office located?	
AL	Lower Mainland Whistler Interior	

Vancouver Island
Sunshine Coast
Decline

QD5: S, QT — Does your organization have multiple locations?

AL
YES
NO
DON'T KNOW

QD6: S, QT — How many people does your organization employ in BC?

AL
1 -5
6-10
11 - 25
26 - 50
51 - 100
101 - 200
More than 200
Decline

QD7: S, QT — Which of the following best describes your organization's 2008 total revenue before taxes? (*select one only)*

AL
Less than $100,000
$100,000 to less than $500,000
$500,000 to less than $1,000,000
$1,000,000 to less than $5,000,000
$5,000000 to less than $10,000,000
$10,000,000 to less than $25,000,000
$25,000,000 or more
Don't know / Decline

DISPLAY — Thank you very much for participating in this survey. All information provided by you will be held in strictest confidence and will only be used for research purposes.

Biogas Market Study

General Summary

Date: April 2010

Presented to • *Présenté à*
Terasen Gas

infocanada@tns-global.com
www.tns-global.com

Contents

At TNS, we know that being successful in today's dynamic global environment requires more understanding, clearer direction and greater certainty than ever before. While accurate information is the foundation of our business, we focus our expertise, services and resources to give you greater insight into your customers' behavior and needs.

Our integrated, consultative approach reveals answers beyond the obvious, so you understand what is happening today – and what will happen tomorrow. That is what sets TNS apart.

Thank you for allowing us to explore your business needs. We hope you will continue to trust TNS to provide the insight you need to sharpen your competitive edge.

1.0 Foreword

1.1 Background

There are two major shifts impacting the energy sector: (1) the marketplace is becoming more diverse and competitive, and (2) environmental issues appear to be increasingly relevant to energy consumers. Being faced with these challenges, Terasen Gas (Terasen) has been repositioning itself as an integrated energy provider that can be both competitive and environmentally friendly (i.e., by minimizing the environmental impact of its activities).

As part of this new positioning, Terasen is exploring renewable energy initiatives that offer customers green energy choices based on biomethane fuels (biogas).

1.1.1 Study Objectives

TNS was commissioned to help Terasen better understand the potential residential and commercial markets for biogas, its market drivers, and sensitivities to different price points for a biogas program. Specifically, the research objectives for both the residential and commercial markets were to measure:

1. Market interest, the potential target market and market size for a renewable energy program (biogas);
2. Market interest and the potential target market for a carbon offset program;
3. Market drivers;
4. Price points and factors affecting price points; and,
5. Customer perceptions of different product offerings.

1.2 Methodological Overview

Data was gathered from both BC households and businesses using an online methodology. An online methodology was used to facilitate a discrete choice analysis – which cannot be done on the telephone or through a mail survey. A discrete choice exercise prompts respondents to choose between a series of program alternatives that trade-off different features. From their choices, it is possible to indirectly measure which elements weigh more heavily in respondents' energy decisions.

1.2.1 Residential Study

An online survey with 1,401 respondents was conducted between November 23 and December 4, 2009 among BC residents (18 years of age or older) using TNS Canadian Facts' online panel. TNS online panels are comprised of households who volunteer to complete surveys from time to time.

A quota sample was used to ensure feedback from three distinct types of residential households:

- Terasen Gas customers (those who receive a gas bill directly from Terasen);
- Indirect customers (gas users who are not billed directly i.e., gas costs are included in strata fees or rent); and,
- Non gas users (those who do not use gas).

Non gas users were included in this study to get a full picture of the BC residential energy market.

The reader is also urged to bear in mind that the sampling unit for this study is the household. All projections are made on the basis of residential Terasen customer households, and not individuals.

1.2.2 Commercial Study

A business sample of over 26,000 customers was provided directly by Terasen Gas to TNS for the commercial study as TNS does not currently have a commercial online panel. Commercial customers were contacted initially by telephone and those which choose to participate were then emailed a link to the online survey.

A total of 500 online surveys were completed by business customers of Terasen between December 14, 2009 and January 22, 2010. A very similar questionnaire was used for both residential and business respondents to allow for comparison between the two groups.

The table below summarizes the final interview counts for both residential and business studies.

Sample Composition

	Actual Interviews	Proportion of Total
	#	%
Residential Study		
Terasen Gas customers (receive gas bill directly from Terasen)	799	57%
Indirect customers (pay gas bill indirectly through rent or strata fees)	200	14%
Non-customers (does not use gas at home)	352	25%
Residents who don't know their energy source	50	4%
Total Residential Interviews	1,401	100%
Business Study		
Total number of interviews	500	100%

2.0 Executive Summary

Both the residential and commercial customer studies produced results that lead to several similar recommendations for Terasen. This is not all that surprising since commercial organizations are managed by individuals (or residents), whose philosophies, attitudes and personal experiences become part of an organization's corporate culture.

In this study, two different types of initiatives were presented to respondents: a biogas program and a carbon offset program. Both stakeholder groups confirmed, at different points in the study that they are more likely to sign up for a biogas program than a carbon offset program. If Terasen were to bring only one of these options to market, we would recommend a biogas program since it would yield a larger market share.

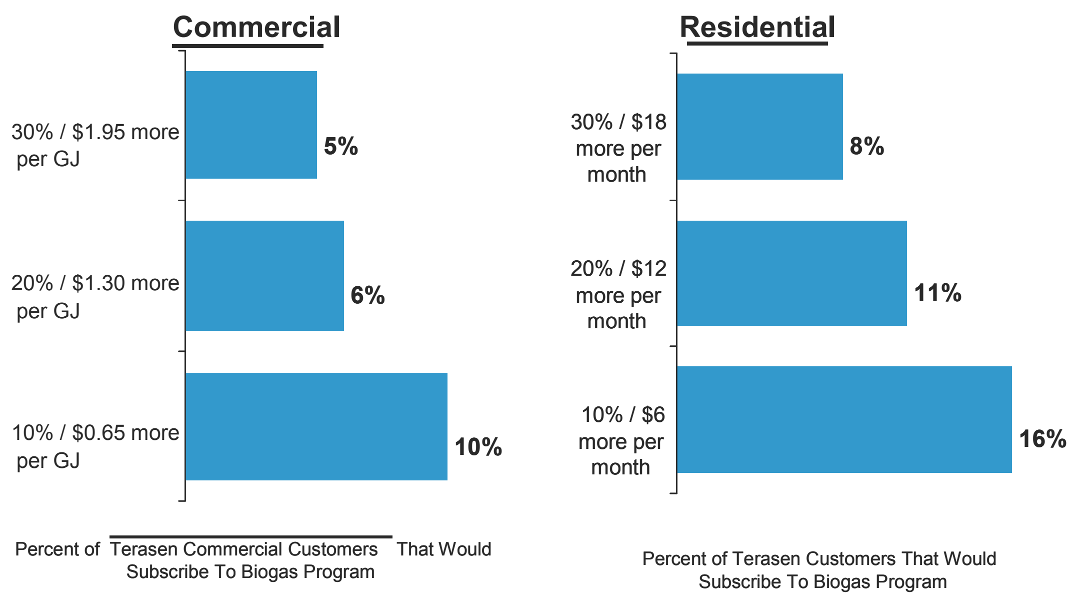
Specifically, if all factors today remained constant (e.g., energy prices remain unchanged), 56% of Terasen's residential customers and 47% of commercial customers would commit to a biogas program on the benefits of the fuel alone. However, this potential market declines if the cost of the program impacts their gas bill. Price is one of the main barriers to a biogas program for many residents and businesses – it prevents many residents and commercial customers from committing to the program. The survey explored pricing levels for a universal price increase as well as a program customers can sign up for at a premium. There was strong support for moderate price increases between 0.5% - 3% for a biogas program where costs were borne by all customers. For a user-pay program, 16% of residential customers and 10% of commercial customers indicated they would enrol in a biogas program at a 10% increase to their current commodity price. Market share projections at various pricing levels for a user-pay biogas program are detailed later in this summary.

Finally, residential customers are more enthusiastic about committing to a biogas program than commercial customers. There appears to be greater hesitation on the part of commercial customers. This fact, coupled with the larger residential market, makes residential households a potentially more lucrative segment to target (than commercial customers).

2.1 Market Projections

Using projections obtained through both the survey data and Terasen's customer data, it is possible to get an idea of what proportion of commercial customers and residential households might potentially subscribe to a biogas program at different price points. The chart below summarizes the results obtained from residential and commercial customers. It shows initial enrolment rates and drop-off levels at key price points for incremental price increases to the commodity rate for a user pay program as well as support for universal price increase levels for a biogas program where costs are borne by all customers.

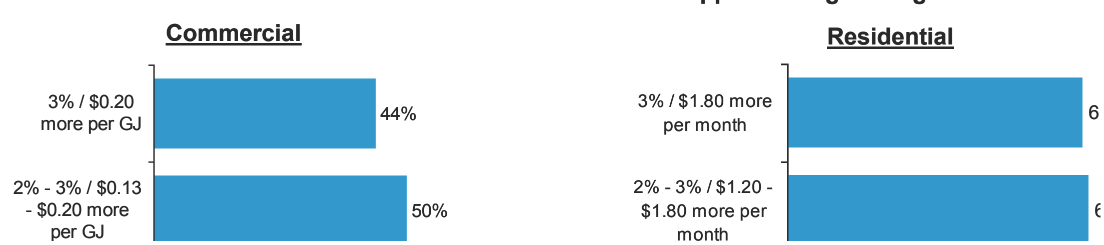
Market Size Projections For a User Pay Program



Above figures are based on share of preference (DCM analysis) with corresponding GHG reduction levels associated with each price point.

Universal Price Increase Support

Percent of Terasen Customers That Would Support a Biogas Program



Above figures are based on a direct line of questioning.

2.2 Pricing

The decision on the optimal price point to introduce a biogas program will depend on Terasen's goals. If it is…

- To maximize household and business involvement, introduce universal price increases borne by all customers;
- To maximize household and customer involvement with premium pricing, increase current prices by 10%;
- To balance Greenhouse Gas (GHG) reductions with premium pricing; increase current prices by 20%; and,
- To offer higher GHG reductions, higher price increases of 30% (or more) will be required.

2.3 Communications Campaign

Enrolment rates for a biogas program will also depend on the strengths of Terasen's communications and marketing. As illustrated in the trade-off analysis, any marketing campaign must demonstrate the environmental benefits of biogas and how it reduces greenhouse gas emissions. The level of greenhouse gas reductions associated with a program has a strong influence on which programs customers will support. This is particularly true for customers that indicate they wish to see a higher GHG reduction for programs with a higher premium.

With respect to the potential target segments for a biogas program, we recommend designing a communications strategy aimed at residential households first. On the residential side Terasen should target:

- Customers who have "green" tendencies;
- Higher educated and higher income households (they tend to be less price sensitive);
- Females (they tend to be more green); and,
- Those who have participated in past energy savings programs.

For commercial customers, a more universal communications strategy should be applied, which demonstrate environmental value for the price paid. Businesses want to see how much of their carbon footprint is being reduced, for each extra dollar that they spend. In this regard, Terasen might consider updating its current billing template to incorporate this additional information.

For Detailed Results – See General Summary

3.0 General Summary

3.1 Residential Findings

As noted previously, Terasen sought input on environmentally-friendly energy initiatives, namely a biogas program and a carbon offset program, from BC residents and commercial customers. This section summarizes results obtained from BC residents (n=1,401). The results gathered among commercial customers are summarized in the next section.

3.1.1 Opinions On Biogas

Approximately two-thirds of residents will support Terasen if the organization opts to invest in biogas projects and an equal number feel Terasen should offer a biogas program for customers. While roughly two-thirds of residents endorse a Terasen biogas program, 56% would sign up for a biogas program. Motivations for enrolment vary, with top reasons among potential enrollees being: providing for future generations; preserving nature, and doing the right thing.

Should Terasen Be Investing In Biogas

	Total
Base: Total respondents	(1,401)
Yes (8-10)	67%
Maybe (4-7)	27%
No (1-3)	2%
Decline	4%

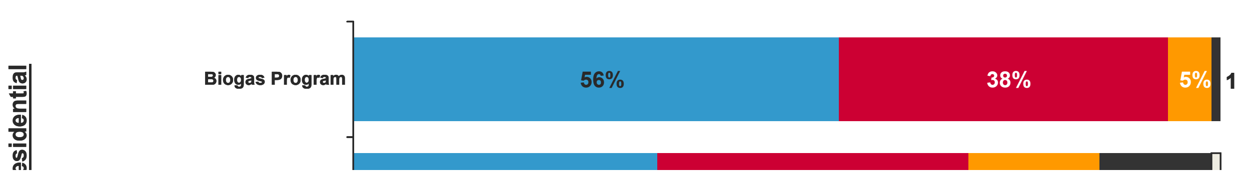
Should Terasen Offer A Biogas Program

	Total
Base: Total respondents	(1,401)
Yes (8-10)	65%
Maybe (4-7)	30%
No (1-3)	1%
Decline	4%

3.1.2. Opinions On Carbon Offsets

Residents were also asked about their support for carbon offsetting programs. While approximately half of residents are aware of carbon offsets, just three-in-ten (31%) indicated likelihood of purchasing them to offset their personal natural gas use. When asked to choose which program they would prefer to see Terasen introduce, residents chose a biogas program over carbon offsets by a three-to-one margin.

Likelihood To Sign Up For Terasen Offered Programs:



3.1.3 Price For Biogas

Residents who expressed an interest in signing up for a biogas program were asked directly whether they would prefer to have a Terasen biogas program funded through a universal price increase (borne by all consumers) or through price premiums for only those who enroll in the program. There was a stronger preference voiced for a universal price increase (47%), compared to a biogas program people can sign up for at a premium (26%), but a considerable number of respondents indicated they did not know which one they would prefer (27%).

As consumers will see the impact of a biogas program on their gas bill, it was also important to explore what size of increase residents might be comfortable with. All respondents were asked universal price increase questions directly in order to explore what level of price increase they would support (up to 3%). This information was supplemented with indirect questions through the discrete choice exercise to explore higher pricing increases (10% to 30% commodity price increase for a program customers can sign up for at a premium).

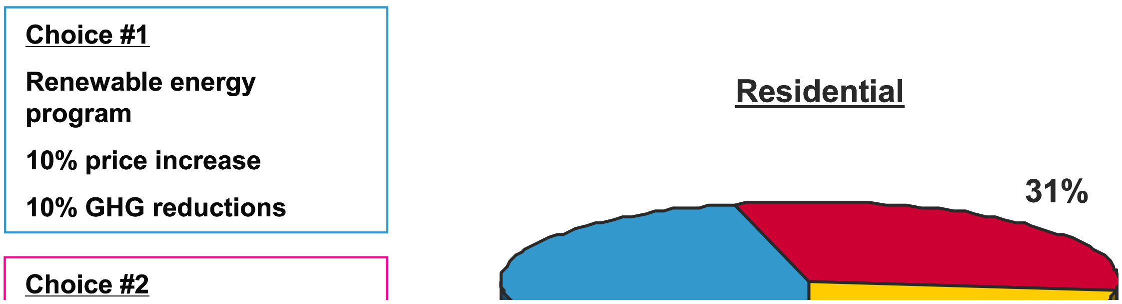
As expected, support for the biogas program decreases as the potential impact on the consumers' gas bill rises. Seventy-eight percent of residential customers indicated they would support a universal price increase of 0.5% to 1%. However, slightly fewer (62%) would still support a universal price increase of up to 3%, revealing there is a substantial proportion of the market willing to financially support biogas initiatives.

3.1.4 Preferred Program Options

The Discrete Choice Model (DCM)[1] included in the survey also indirectly measures which features weighed more heavily in residential energy choices. The discrete choice exercise explored the relationship between the price of renewable energy options (measuring steeper price increases of 10%-30%) and greenhouse gas reductions. These results confirm that price is an important consideration, but can be counteracted by the prospect of disproportionately higher greenhouse gas reductions (e.g., 20% price increase yielding a 30% GHG reduction is as popular as an option that sees a 10% cost increase and a 10% reduction).

In the following simulation, we compare three different biogas programs that respondents can choose from (a program with a 10% GHG reduction and 10% price premium; a program with a 20% GHG reduction and a 20% price increase; or a program with a 30% GHG reduction and 30% price increase). The program with a 10% GHG reduction and 10% price increase is preferred by 46% of residential customers who said they would sign up for a biogas program. The two choices with the higher price increases were preferred by a smaller proportion of residential customers.

[1] A Discrete Choice Model (DCM) asks respondents to choose between a series of program alternatives that trade-off on different features. From their choices, a DCM model is able to indirectly measure which elements weighed more heavily on a respondent’s selections. In this study, a model was built on three dimensions – (1) type of energy initiative, (2) percent reduction in GHG levels, and (3) effect on monthly gas bill. Thirty-six possible pairings of choice sets were built into the questionnaire, based on different permutations of the three dimensions. Each respondent was presented with a random set of 16 pairings and asked to select the scenario they preferred in each pairing.



3.1.5 Estimating Market Potential

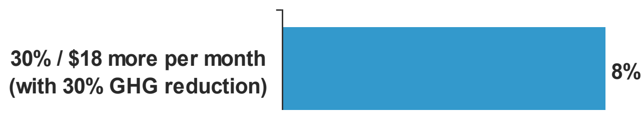
Using the survey data, it was possible to generate rough estimates of potential market share for a biogas program. The projected market estimates were calculated based solely on what respondents told us. Knowing this, we would caution that these figures should be considered best case estimates. The reason for caution is two-fold:

- People do not always do what they say – we often fall short of our intended goals; and,
- Respondents sometimes have the tendency to provide answers in a manner consistent with how they perceive we want them to answer – in this case, to sign up for a biogas program because it has positive impacts on our environment.

The market projections in this section of the report are based on Terasen customers who receive a gas bill directly from Terasen as these customers are accessible to Terasen and have the greatest control over whether or not their households would sign up for such program. We excluded all other residents from this analysis.

The reader is also urged to bear in mind that the sampling unit for this study is the household. All projections are made on the basis of residential Terasen customer households, and not individuals.

The chart on the following page uses the market projections to get an estimate of what proportion of residential households might potentially subscribe to a biogas program province-wide at different price points. Among Terasen residential customers, 56% indicated a willingness to sign up for a biogas program if there are no cost implications. As soon as the biogas initiative has cost implications on the residential gas bill, enrollment levels begin to drop off. It is estimated that 16% of those interested in signing up for a biogas program would support a user pay premium of 10% or $6 per month – if it results in a 10% reduction in GHG levels.



3.1.6 Profile Of Potential Biogas Market

Generally speaking, the demographic profile of residents voicing support for biogas initiatives does not differ greatly from that of residents who are not supportive. However, education and income appear to be two factors that differ between supporters from detractors. This information may help Terasen direct marketing efforts towards receptive customers.

3.2 Commercial Findings

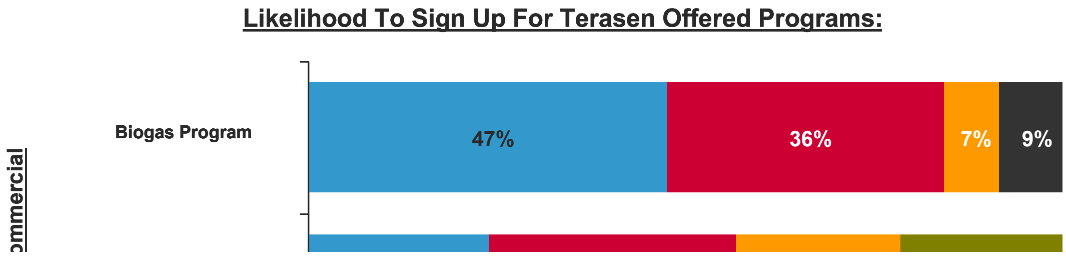
The following section highlights results gathered among Terasen's commercial customer base (n=500).

3.2.1 Opinions On Biogas

Similar to support levels found among BC residents, 67% of commercial customers will support Terasen if the organization opts to invest in biogas projects. Support for Terasen offering a biogas program is higher among commercial customers than among residents (71% support the initiative compared to 65% of residents). Similar to the pattern seen among residents, support for a biogas program is strong, but a smaller proportion (47%) indicates they would actually enroll in it. Motivations for enrolment among commercial customers vary, with primary reasons being: doing the right thing; providing for future generations, and preserving nature.

3.2.2 Opinions On Carbon Offsets

Commercial customers are more aware of about carbon offsets than residents (66% awareness versus 50% among residents). Despite higher awareness levels, just 24% indicated likelihood of purchasing them to offset their business' natural gas use. When asked which program they would prefer to see Terasen introduce, commercial customers chose a biogas program over carbon offsets by a three-to-one margin, mirroring the residential findings.

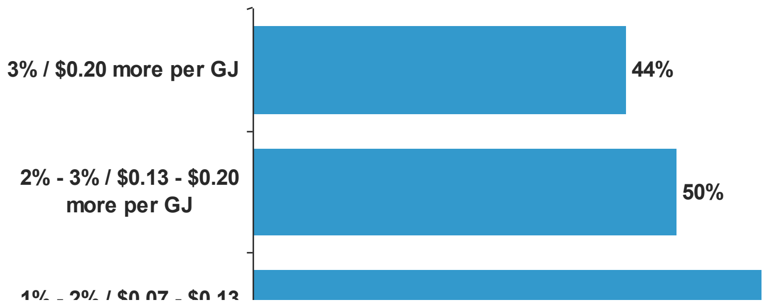


3.2.3 Price For Biogas

As with residents, commercial customers interested in a biogas program were asked directly whether they would prefer to have a Terasen biogas program funded through a universal price increase (borne by all consumers) or through price premiums only for those who enroll in the program. Unlike residents who were unable to provide a conclusive assessment of funding options, commercial customers came out strongly in support of a universal price increase (supported by 60% of commercial respondents). Nineteen percent supported a premium price increase and 21% said they did not know.

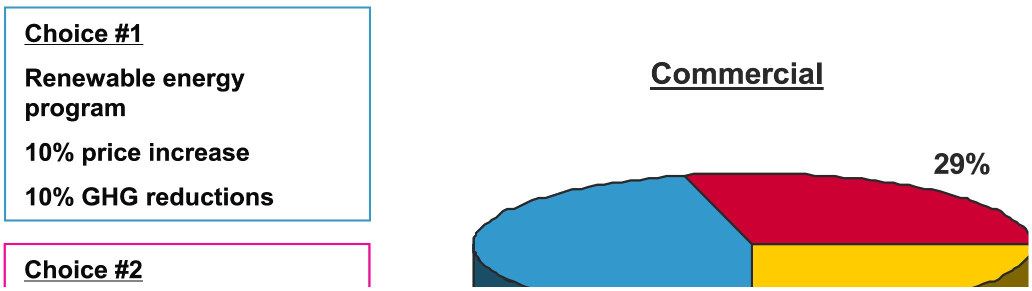
It was also important to explore what size of increase commercial customers would be comfortable with for a universal price increase versus a voluntary program. As with the residential surveys, this information was gathered through a *direct* question about support at different price points (up to a 3% commodity price increase for a universal price increase) and *indirectly* through the discrete choice exercise (for 10% to 30% commodity price increase for a program customers can sign up for).

Overall, commercial customers are much more apprehensive than residential customers when it comes to supporting a biogas program when there are cost implications. Half of commercial customers would support this concept if it meant their gas bill would increase by up to 3%.



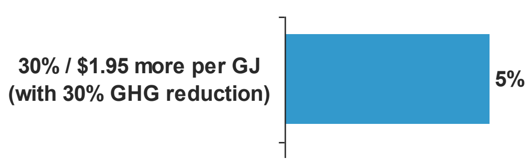
3.2.4 Preferred Program Options

The Discrete Choice Model (DCM) included in the survey also indirectly measured which features weighed more heavily in commercial customers' energy choices. The discrete choice exercise explored the relationship between the price of renewable energy options and greenhouse gas reductions. Consistent with the residential findings, these results confirm that price is an important consideration, but can be counteracted by greenhouse gas reductions proportionally larger than price increases (e.g., 20% price increase yielding a 30% GHG reduction is as popular as an option that sees a 10% cost increase and a 10% reduction). Indeed, results show commercial customers are particularly concerned about reducing GHG levels. However, like with residential customers, commercial customers also prefer the option of a 10% GHG reduction and a 10% price increase, among the three options presented in the DCM simulation on the following page.



3.2.5 Estimating Market Potential

The chart below uses market projections to develop an estimate of what proportion of businesses might potentially subscribe to a biogas program across the province. As noted earlier, 47% of commercial customers indicate willingness to sign up for a biogas program if there are no cost implications. As soon as the biogas initiative has cost implications on the gas bill, enrollment levels begin to drop off. It is estimated that 10% of those interested in signing up for a biogas program would support a user pay premium of 10% or $0.65 more per GJ – if it results in a 10% reduction in GHG levels.



3.2.6 Profile Of Potential Biogas Market

The commercial customers most likely to enroll in the biogas program include those who have participated in past energy saving programs, single location organizations (as opposed to those with multiple locations), and those who express concern for the environment.

Technical Appendix

Overview

A total of 1,401 online interviews were conducted between November 23 and December 4, 2009 with a sample of British Columbia residents. In addition to these residential interviews, 500 interviews were conducted with commercial customers of Terasen from December 14, 2009 to January 22, 2010. Results obtained from this survey provide valuable insights into understanding perceptions of Terasen and feature preferences for a renewable biogas program.

Sample Frame And Design

The samples used in this survey were drawn from two different sources. TNS' Canadian online adult panel was used to intercept BC residents. All BC communities were sampled. A quota cell design was used for this survey to ensure that a specific sampling level was achieved with respect to Terasen's own customers and non-customers. The number of completed interviews for each quota group are outlined below.

Sample Composition

	Actual Interviews	Proportion of Total
	#	%
Residential Study		
Terasen Gas customers (receive gas bill directly from Terasen)	799	57%
Indirect customers (pay gas bill indirectly through rent or strata fees)	200	14%
Non-customers (does not use gas at home)	352	25%
Residents who don't know their energy source	50	4%
Total Residential Interviews	1,401	100%
Business Study		
Total number of interviews	500	100%

Respondent Selection And Qualification

Respondents were selected differently for the two studies. On the residential side, respondents were randomly selected from TNS' online panel. This includes both gas users and non-users. On the commercial survey, respondents were restricted to Terasen customers and drawn randomly from Terasen's database. On both studies, respondents who work for a utility, gas marketer, the media, a research or advertising firm, were screened out of the study.

Questionnaire Development

The residential questionnaire was developed by TNS Canadian Facts in consultation with Terasen Gas. Prior to the start of interviewing, a pretest was conducted over the first weekend of field to ensure the workability of the questionnaire and to finalize question sequencing.

The commercial questionnaire is almost identical to the residential questionnaire with slight modifications.

Data Collection

Residential respondents were recruited from TNS' online panels and directed to the survey site to complete the survey.

Commercial respondents were recruited from Terasen's customer database. These respondents were first approached by phone. Once their participation was secured, they were asked for their email addresses, so that the survey link could be sent to them. The survey had to be conducted online because the DCM analysis contained in this research project requires an online interface with respondents.

Survey Margin Of Error

Please note that margins of error apply to randomly selected samples. Residential panel samples are self selected and therefore the following margin of error figures are presented as a guide for readers. The overall sampling error for 1,401 total residential interviews at the 95% confidence level is approximately ± 2.6%. For example, if 50% of all residents surveyed stated that they have heard of carbon offsets, then we can be sure, nine times out of ten, that if the entire population had been interviewed, the proportion would lie between 47.8% and 52.2%.

When a segment of the entire data is analyzed, the sampling error increases. For example, the overall sampling error for data based on 200 interviews at the 95% confidence level is approximately ± 7.0%. In this case, using the scenario where respondents surveyed state that they would purchase a carbon offset, then we can be sure, nine times out of ten, that this proportion would lie between 43.0% and 57.0%.

The commercial survey results are subject to margins of error. At the 95% confidence level, the margin of error for the 500 commercial customers' interviews is ± 4.4%.

A copy of the invitation and questionnaire used in this survey are appended to this report.

1.0 Reference: Introduction

Exhibit B-1, Section 1.1, page 1

1.1 Please explain why Terasen Gas Inc. (Terasen or TGI) has not proposed to offer the Green Gas program through a non-regulated entity?

Response:

The question is founded upon the incorrect premise that entities engaged in the Biomethane supply chain are not subject to regulation by the Commission. In fact, any entity that engages in the production (upgrading), distribution and sale of Biomethane to customers is engaged in a public utility service that is subject to regulation under the *Utilities Commission Act*. The end-to-end business model for the Green Gas offering entails numerous utility functions that are most efficiently and cost-effectively carried out by TGI (as opposed to another regulated business), in much the same way as the customer choice program.

The Commission's jurisdiction extends to "public utilities", as defined in the *Utilities Commission Act.* The term "public utility" is defined in section 1 as follows:

> "public utility" means a person, or the person's lessee, trustee, receiver or liquidator, who owns or operates in British Columbia, equipment or facilities for
>
> > (a) the production, generation, storage, transmission, sale, delivery or provision of electricity, natural gas, steam or any other agent for the production of light, heat, cold or power to or for the public or a corporation for compensation… [Emphasis added.]

This definition covers both the upgrading of biogas to biomethane and the notional sale of biomethane gas to customers.

- **Sale of Biomethane to the Public:** Biomethane itself is an "agent" that is used for the "production of… heat", which in the context of the green gas offering, will be sold to the "public [i.e. TGI customers]… for compensation". If an entity other than TGI were to sell the biomethane to TGI for distribution to its customers, then the definition would still apply for the same reasons, except that the "agent for the production of … heat" would be sold to "a corporation for compensation" (i.e. TGI). In other words, any entity that sells upgraded biomethane to either the public or to TGI, will be subject to the Act's provisions and the Commission's regulatory oversight. Thus, TGI's biomethane offering is a regulated service that requires Commission-approved rate schedules in order to be sold to customers.

- **Biomethane upgrading equipment** is equipment that is used for the "production" of an "agent" (biomethane) that is used for the "production of… heat", which in the context of the green gas offering will be sold to the "public (i.e. TGI customers)… for compensation". If an entity other than TGI were to own the upgrading equipment so as to sell upgraded Biomethane to TGI, the definition of "public utility" would still apply for the same reasons, except that the "agent for the production of … heat" would be sold to "a corporation for compensation" (i.e. TGI). In other words, any entity that owns or operates biomethane upgrading equipment, and who sells the upgraded biomethane to either the public or to TGI or directly to any other corporation, will be subject to the Act's provisions and the Commission's regulatory oversight.

The definition of "public utility" includes the following exceptions:

> (c) a municipality or regional district in respect of services provided by the municipality or regional district within its own boundaries,
>
> (d) a person not otherwise a public utility who provides the service or commodity only to the person or the person's employees or tenants, if the service or commodity is not resold to or used by others,
>
> (f) a person not otherwise a public utility who is engaged in the production of a geothermal resource, as defined in the Geothermal Resources Act, or
>
> (g) a person, other than the authority, who enters into or is created by, under or in furtherance of an agreement designated under section 12 (9) of the Hydro and Power Authority Act, in respect of anything done, owned or operated under or in relation to that agreement;

Since none of these exemptions capture any aspect of the Green Gas Offering, the upgrading of biogas to biomethane and the provision of biomethane to customers by TGI will be subject to Commission regulation regardless of the legal entity that provides these services. This is why TGI cannot consider offering the Green Gas offering through an NRB.

It makes sense that the Commission's jurisdiction extends to biomethane upgrading, whereas it does not extend to the wellhead production of natural gas. Natural gas is an energy source that is regulated from the wellhead to the customer's home by multiple regulatory bodies. The British Columbia Oil and Gas Commission and the National Energy Board regulate the extraction, production and transportation of natural gas through processing facilities and gas pipelines to a public utility's gas distribution main. From that point onward natural gas is regulated by the Commission. The regulation of this commodity engages environmental, safety, reliability, and economic concerns, and ensures that the public interest is protected in the delivery of this resource to ratepayers. If the Commission were to find that biogas upgrading facilities were not subject to the Act's provisions, the result would be a regulatory gap that would leave biogas upgrading facilities without an active regulator, which TGI submits would not be in the public interest. While there is legislation that governs certain aspects of the collection of gas from digesters and landfills, such as the *Gas Safety Act* and the *Landfill Gas Management Regulation*, there is no regulator, other than the Commission, with any jurisdiction to actively monitor and ensure the safe and also reliable operation of biogas upgrading facilities. Specifically, there are no provisions of the *Pipeline Act* or the *Petroleum and Natural Gas Act* that would provide the Oil and Gas Commission with jurisdiction to regulate these facilities. Had the legislature intended to exempt these facilities from the Commission's jurisdiction, it could have done so through an exemption in the definition of "public utility", as it has done in the case of persons engaged in the petroleum industry or in the wellhead production of oil, natural gas or other natural petroleum substances. There is no such exemption, and consequently, the Commission should find that it is required to regulate these facilities as it is in the public interest to do so.

The analytical approach described above has been implicitly accepted by the Commission in other applications. In the Dockside Green Energy LLP Decision and Reconsideration, the Commission accepted that DGE's construction and operation of a biomass facility to provide hot water heating to the Dockside Green development was subject to the provisions of the Act. For the purposes of the application of the Act, there is no meaningful distinction between the Dockside Green biomass facility as a facility for generating an agent for the production of heat and biogas upgrading facilities that accomplish the same outcome.

The fact that these activities are subject to Commission jurisdiction does not mean that the commission needs to actively regulate the upgrading entity in any way (just as the Commission currently does not actively regulate small entities such as strata corporations that meet the definition of "public utility"). For example, "passive regulation" may be warranted in the case of third parties engaged in upgrading because biomethane pricing is addressed by the review of TGI's purchase agreements. The ability to address reliability issues directly with a non-municipal third party upgrading entity if need be is nonetheless of value.

1.2 Would it be possible for Terasen to offer the Green Gas program through a non-regulated entity? If not, explain what factors would prevent such a structure?

<u>Response:</u>

No, it would not be possible because the activities contemplated are, by definition, regulated activities. See the response to BCUC IR 1.1.1.

1.3 What would be the disadvantage of offering the Green Gas program through a non-regulated entity?

Response:

It would not be possible to offer the program through an NRB because the activities contemplated are, by definition, regulated activities. TGI can undertake these regulated activities in a manner that best serves customers, relative to another (regulated) entity. See the response to BCUC IR 1.1.1.

1.4 How does TGI propose to insulate general rate payers from any losses incurred if the BioGas Program is not successful?

Response:

Extensive market research conducted by TNS Canadian Facts and supplemented by secondary research performed by Terasen Gas has led to the conclusion that the proposed Green Gas program will be successful and that demand will exceed the amount of supply the Company is able to develop in the near term. The likelihood of an unsuccessful program resulting in costs to all customers is very low, but the Company is cognizant that this risk exists. Terasen Gas has outlined throughout the Application, but particularly in Section 11, the steps Terasen Gas has taken to mitigate the potential risk of stranded costs. In the unlikely event that facilities are stranded and cannot be redeployed, the prudently incurred stranded costs should be borne by customers as cost of service.

To expand on TGI's response, the steps undertaken to mitigate the risk of stranding assets are summarized below:

1. **Extensive Market Research**

As described on page 52 of the Application, the amount of initial supply being brought onto the Terasen Gas distribution system coincides with the industry average residential participation rate in green energy programs. Our market research, as illustrated in Figure 5-5 on page 46 of the Application, indicates that the British Columbia residential market could be up to eight times the industry average. In addition, the same illustration shows that there is significant commercial market potential as well as significant industrial market demand from customers such as Central

Heat. Finally, there is evidence of an export market for Biomethane. Terasen Gas believes that the market for Biomethane far exceeds the amount of Biomethane we are proposing to develop in this Application, and we have committed to only develop additional supply projects as this demand becomes proven.

2. Supplier Evaluation

The Company has evaluated, and will carefully evaluate in the future, our suppliers and potential partners to ensure their technical and financial capability. This is discussed in more detail in Section 8.4.3 of the Application. We have also reduced the likelihood of supplier failure by providing our experience and expertise in the ownership and management of gas utility assets such as the Biogas upgrading equipment. This is discussed in greater detail in Section 8.3.2 of the Application.

3. Portability of Projects

TGI has, to the extent possible in each respective project, constructed our facilities in such a manner that they can be readily removed and either re-deployed or liquidated in the event a specific project fails. This is discussed in greater detail in Sections 9.2.7.3 and 9.3.6.3 of the Application.

With respect to cost recovery, the Company believes that, as a general principle supported by the *Utilities Commission Act*, prudently incurred costs should be recovered from existing customers. Assets may become stranded for reasons beyond the control of TGI, and the shareholder should only bear costs when the investment was imprudent in light of the circumstances known at the time, or TGI’s improper management of the investment contributed to stranding. The decision to invest in biomethane makes sense (i.e. is prudent) in the circumstances. The proposed Green Gas program makes use of existing facilities and maintains throughput on the system that might have otherwise left for energy options perceived as being more “green”. The leveraging of the existing system benefits all customers who contribute to the costs of the system because there are more customers over which to allocate the costs of the system. In this way, the proposed Green Gas program prevents potentially otherwise necessary delivery rate increases for all customers. Please see the response to BCUC IR 1.10.5 for further detail. The introduction of the Green Gas program is also in keeping with the Government’s Energy Objectives under the *Clean Energy Act*, as described on pages 25 to 27 of the Application.

In closing, Terasen Gas expects that, based on all available evidence, the proposed program will be a success. The Company has nonetheless diligently worked to mitigate against the risk of assets becoming stranded.

- Cost of collection assets = $4,800,000
- Percentage cost of collection assets to total project cost = ($4,800,000 / $6,588,800) x 100% = 73%.

As illustrated above, the capital cost of Biogas collection assets makes up the largest portion of the investment in an overall Biogas project.

2.2 What expertise does TGI have with respect to biogas upgrading processes and technology? Why is it important for TGI to control the upgrading of biogas when monitoring this activity as done with the Catalyst Project would be sufficient?

Response:

TGI believes that owning and operating biogas upgrading plants is the best way to ensure that biomethane is produced reliably. TGI has a strong background in equipment operation and maintenance similar to biogas upgrading so it is a natural extension of the utility. Each of the questions above will be addressed in turn below. TGI also discusses why it was appropriate in the case of the Catalyst project for Catalyst to retain ownership of the upgrading facilities.

Importance of TGI owning upgrading equipment

TGI has taken the approach of considering the needs of potential partners when discussing projects. In some circumstances, project partners have expressed a desire for TGI to own the upgrading equipment for their own business reasons. Two primary reasons for TGI involvement have surfaced over the past year.

The first reason is financial. Developers have indicated that it is typically easier to obtain financing when an experienced, reputable and reliable partner like TGI is involved in the upgrading. Further, partners may not have access to enough capital to put both a raw biogas generating facility (such as a digester) and an upgrading plant in place. In the case of a partner like a municipality, the need to ask for less capital from taxpayers is seen as attractive.

The second reason is related to expertise. Developers have indicated that a partner with experience in gas processing and gas technology is attractive.

As discussed in Section 8.2 of the Application, TGI believes that controlling the upgrading process will provide improved control over the quality of the biomethane produced and increase reliability of supply and therefore benefit customers and ensure the success of the biogas program.

This is important for several reasons.

1. TGI is the face of the biomethane program to the customer. By owning upgrading equipment, TGI has the ability to better respond to customer concerns and demand. The feedback path is more direct and therefore more effective in getting positive results more quickly.

2. TGI is motivated to provide the best quality gas possible. In some cases, an independent operator may choose to reduce operating costs associated with upgrading by sacrificing maintenance which could result in lower quality gas or reduced reliability. Or, an independent operator may choose to operate so as to meet only the minimum required gas specification. TGI can take advantage of existing resources by absorbing some of the additional work associated with a biogas plant without requiring additional staff. This approach to resource maximization tends to improve cost effectiveness of supply.

3. TGI service organization is in place. TGI customers will benefit from an existing business and service infrastructure that can respond quickly to customer concerns and issues in the field. A potentially quicker response time will improve the total amount of production time over the year and result in higher customer satisfaction.

4. TGI believes that two ownership models increases flexibility in developing projects which vary from site to site. Limiting consideration to only one model could restrict supply development and potentially expose TGI to the risk of increased supply costs and therefore a higher price for the customer.

In light of the importance of securing a reliable supply of quality biomethane, TGI believes that it is important for TGI to retain control over upgrading facilities unless it can be assured that another party is capable of delivering the reliable supply on a cost effective basis. TGI's consideration of the Catalyst project in this context is discussed later in this response.

TGI expertise and competence

TGI recognizes that at the time of filing there are no operating biogas upgrading plants in the province and therefore no experienced operators. In the absence of these operators, TGI can fill this role because it has expertise in many areas closely linked to biogas upgrading processes and technology. TGI also has experience in operating the Tilbury LNG plant which is a complex natural gas processing plant.

The biogas upgrading process is described in more detail in the Biomethane Application (Section 2.5), however, a brief, high level description is helpful to draw comparisons to the natural gas industry. Raw biogas is composed primarily of flammable methane, carbon dioxide and other contaminant gases. The upgrading process is a straightforward process. Raw biogas is flowed through a series of vessels at a moderate pressure (slightly higher than TGI distribution pressure) which are used to remove contaminants from raw biogas. Many of the components that make up an upgrading plant are the same as those TGI uses in its system every day. Specifically, Terasen Gas has a long history of expertise in the following areas:

1. Flammable gas safety and management. Raw biogas and biomethane would be managed in the same way as natural gas. Terasen gas already has the expertise and equipment required to ensure safe operation and maintenance of biogas upgrade equipment.
2. Gas composition and quality monitoring. Terasen gas regularly monitors gas composition at multiple supply points across the existing system to ensure accurate billing and measurement for customers.
3. Leak management. Terasen Gas already has a service organization trained to respond to leak concerns from customers, to find leaks and to fix leaks when required.
4. Component Familiarity. Pressure vessels and ancillary equipment operation such as compressors, valves, regulators, control systems and safety systems are the same as used for natural gas. Biogas upgrading equipment will be designed and built using essentially the same basic components that Terasen Gas uses across its system in regulating stations, pressure let down stations, compressor stations and even at homes and businesses. The equipment used on a biogas upgrading plant will be designed for the same life, safety, durability and performance as used on the Terasen Gas system.
5. Gas processing. TGI has proven to be a competent and safe operator of the Tilbury LNG plant. The plant includes components which remove contaminants and operate at process conditions well outside of typical distribution system conditions.

The operation and maintenance of an upgrading plant is therefore complementary to existing TGI assets. This is demonstrated in the design, operation and maintenance of existing facilities and assets across the province.

Reasons for Catalyst project ownership model

The Catalyst project represents an exception to TGI's view that TGI should own and operate the upgrading facilities, and the arrangement reached with Catalyst was largely a product of the circumstances.

Catalyst Power Inc. was able to successfully attain grant funding which significantly reduced the initial capital required for the purchase of a biogas upgrading plant. TGI involvement after the award of the grant would have complicated the funding arrangements. In addition, the project timeline would have required TGI to invest much earlier in the project, so it was decided that a Catalyst-owned upgrade plant was the best way to move the project forward according to a timeline that did not jeopardize the viability of the project. In creating the biogas program proposed in the Application (including supply projects), TGI hopes that a more efficient process for approval will be developed such that timelines for investment do not affect the viability of any future projects.

It is important to note that Catalyst Power Inc. is also interested in developing further projects and is openly discussing a business model that has TGI owning the upgrading equipment. Catalyst Power Inc. has stated that it is in a better position to attract partners and to secure financing for future projects when TGI has a larger stake in the project.

TGI believed that it was important to develop a project with Catalyst using a non-preferred model and begin to establish a supply and market for biomethane. This project is considered critical in providing the first biomethane to TGI customers. Further, Catalyst Power Inc. was able to demonstrate that it could be a reliable partner, and therefore limit the risk of supply by cooperating with TGI at all phases of the project development. This included keeping TGI informed of the success against major hurdles such as getting permit approvals, securing waste contracts, securing equipment orders and providing land for Terasen Gas assets.

TGI recognizes that reliability is best secured by TGI owning upgrading facilities, but TGI believes that there is value in providing a starting point for the biogas program and a means of providing biomethane as a product to TGI customers, provided that a reliable partner can be found.

2.3 TGI states that: *"The Company is actively pursuing independent partners who might be entrusted with the task of acquiring Biogas and upgrading it to pipeline –quality Biomethane which Terasen Gas can then purchase, inspect, and inject into our distribution system provided they can meet safety and reliability standards required for our customers."*

How is TGI attempting to attract independent partners?

Response:

In this context, TGI defines an independent partner as parties other than TGI interested in owning and operating biogas upgrading facilities and would, therefore, supply only a finished biomethane product to TGI. These parties may also own and operate biogas generation facilities.

TGI is allowing project developers to decide the best approach to business agreements within the context of the two ownership models. In any communication, it is clear that TGI has a preference for owning upgrading equipment, but is willing to negotiate alternative arrangements.

This process started with a Request for Expressions of Interest in the fall of 2008, where TGI openly invited potential project partners to put forward proposals. The process was intentionally left flexible to allow for potential project developers to approach TGI with creative solutions with no preference indicated for the business arrangement.

Since that time, TGI has continued to make it clear that an independent partner approach is acceptable.

TGI has initiated discussions with known project developers who have experience in developing waste to energy projects in other regions (outside of British Columbia) to begin to explore possible partnership arrangements. This includes companies such as Waste Management, Linde North America, Blue Source, Yield Energy and Harvest Power Inc.

TGI has also met with major biogas upgrading equipment manufacturers (e.g., Xebec, Flotech, Air Liquide) and outlined the business model to them so that they could make any project developers that approach them aware of TGI's approach.

Further, TGI has publicly promoted both ownership models when presenting on the topic of biogas at conferences. TGI has also made it clear in other media such as the website that project developers are free to develop proposals that best suit their needs.

In the future, TGI may offer further public requests for expression of interest or develop a call for biomethane.

Today, however, TGI believes that an approach that favours independent producers may create upward pressure on biogas customer rates. TGI believes that the best way to encourage supply development while ensuring supply reliability and keeping biogas customer rates competitive is to remain open to independent partners while pursuing projects where TGI would own upgrading equipment.

TGI believes that many municipalities and regional districts can benefit the public by partnering with TGI to cooperatively reduce GHG emissions, while at the same time meeting the demands of TGI customers for a renewable energy product offering.

3.2 TGI states that (page 27): *"Our relationship with municipalities and regional districts have led us to believe that local governments would prefer to work with large, experienced organizations such as Terasen Gas. Local governments, as a result of the nature of their mandate, are highly risk-averse organizations which have shown a preference for partnership with stable, experienced, transparent, and safety-oriented organizations such as Terasen Gas."*

Why does TGI consider it has experience in the upgrading of biogas to biomethane?

Response:

TGI believes that the upgrading of biomethane is a natural extension of existing competencies within the Company. Though TGI does not yet have experience in biogas to biomethane upgrading, the skills required to safely and reliably operate upgrading equipment do exist in the Company. TGI has outlined some of these skills it possesses in the response to BCUC IR 1.2.2 to support this statement. Local government partners (such as municipalities and regional districts) and other project partners value more than direct biomethane upgrading experience. Project partners value the experience TGI has in managing assets in general. When partnering with TGI, project partners can be assured that TGI has qualified personnel in their respective area of expertise and that TGI will be open and transparent with the financial aspects of any project. This has been seen as a favourable option over allowing independent partners (who may or may not have this expertise) to develop projects in cooperation with project partners. In some cases, project partners do not want to take the time and effort to establish a working relationship with a third party. They do not want to take on this added risk in dealing with a new third party but rather they look to TGI to fill this need.

3.3 Considering TGI's statement, how can a non-regulated business that has expertise in upgrading of biogas to biomethane compete for this business if the regulated utility has a significant advantage with a market presence established through the gas distribution business?

beginning in 2012 when the program will be expanded to commercial customers through Rate Schedules 2B and 3B. TGI believes that allocating costs on this principled basis produces a fair result for all customers and the shared costs of this program at this early stage are much smaller than the Customer Choice Program.

16.2 Should Gas Marketers be allowed to buy biomethane gas directly from a supplier or upgrade the gas themselves and inject it into the Terasen Gas system.

Response:

In providing a response to this question, Terasen Gas assumes that Gas Marketers referred to in this question are limited to those participating in the Customer Choice program. In terms of "allowing" Gas Marketers to inject biomethane into the Company's system, "allowing" involves two aspects, one of which is technical in nature and the other involves regulatory considerations.

From a technical perspective, TGI agrees that there are two general manners in which a Gas Marketer could attempt to provide biomethane into the Company's system. One involves buying biomethane gas directly from a supplier outside the Company's service territory and transporting it to the Terasen Gas system, providing this supply under the business rules of the Essential Services Model. The other involves Gas Marketers upgrading the gas themselves, or purchasing upgraded gas, and then injecting it into the Terasen Gas distribution system. In this second case, the Gas Marketers would only be injecting biomethane into the Company's system and would not be able to provide this gas to specific customers. In order to enable Gas Marketers to provide biomethane directly to customers would require a wheeling agreement with the Company to enable the transport of this gas first to either one or all of the receipt points. TGI may be willing to consider such arrangements in a future phase of the program when more supply is developed or available.

As TGI stated in its Application, biomethane project proponents who meet TGI's financial, safety, and technical standards will be allowed to interconnect their projects to TGI's system. In this respect, TGI sees no difference between a gas marketer wishing to enter into the biomethane production business, or any other business venture (such as Catalyst) that wishes to do the same. TGI will evaluate all project proponents on the same basis when determining whether to allow them to interconnect their project(s) to the Company's system.

The question of "allowing" also involves regulatory considerations. To the extent that these activities are public utility activities, the Commission ultimately has jurisdiction over these matters. Please see the response to BCUC IR 1.1.1 for further discussion of regulatory considerations.

customer demand. Specifically, the research done shows a 16% demand while TGI has chosen to use an industry average of 2.2%.

2. In the unlikely event that customer demand is lower than expected, TGI has the opportunity to sell biomethane via schedule 11 and schedule 30 to non-residential customers. Further, if there is a shortfall in demand due to the blend offering (10%), there are customers who will buy biomethane at 100% purity.

Given these facts, if new supply projects come forward, TGI intends to continue to pursue new supply development projects and will file the supply contracts with the BCUC.

Please see the response to BCUC IR 1.21.2 for more details.

21.4 Has any supplier approached TGI to discuss supplying consumer-ready biomethane to the TGI gas distribution system? If not, please explain why this might be.

Response:

TGI understands "supplying consumer-ready biomethane" to mean the supply of biomethane to TGI according to the second model proposed in the Application (where TGI has ownership and control over the interconnection facilities only).

Yes, several potential suppliers have approached TGI to develop consumer-ready biomethane projects. In the context of the Application, the Catalyst Power Inc. Project also fits this definition.

TGI is willing to accommodate this ownership model (please refer to Section 8.3 of the Application) provided that suppliers can demonstrate an ability to provide a consistent, reliable supply of biomethane. Please refer to the response to BCUC IR 1.22.3 for a description of the criteria which TGI intends to use when evaluating supplier reliability.

TGI has had discussions with potential suppliers, which has revealed that these suppliers are considering partnering with TGI in an arrangement where TGI would own upgrading equipment for their own business reasons. TGI believes that it is absolutely necessary to provide the flexibility of both ownership models in order to allow the market to develop.

21.6 If TGI becomes an established and significant supplier of biomethane, will other potential suppliers be competitively disadvantaged or face barriers to entry in the biomethane supply market?

Response:

TGI has approached this response on the basis that "supplier of biomethane" refers to TGI's involvement in upgrading facilities, as TGI does not currently intend to be involved in the production of raw Biogas.

The Commission's interest in the competitive position of TGI relative to other companies engaged in the business of upgrading biogas must be founded in matters relevant to its statutory mandate. The regulation of competition *per se* falls beyond the Commission's jurisdiction. The Commission's interest in this context must be in ensuring that there is a reliable and safe supply of biomethane for customers at a reasonable price. In the long term, this objective is achieved by TGI having access to a multitude of biomethane supply options (i.e. competition among biogas and biomethane projects) that might be expected to act as a check on supply costs over time. TGI's participation in upgrading, as circumstances require or as proponents desire, furthers, not hinders, this objective of developing the supply market and providing a favourable influence on costs over time. Until there is a well established supply market for biomethane that requires biogas project proponents to compete against each other on price, the presence of competition for the provision of upgrading facilities is most relevant to the feasibility or profitability of biogas projects for the project proponent, not the cost effectiveness of the biomethane service for TGI customers. This is explained further below.

TGI believes that it has a reputation as a qualified provider of safe and reliable public utility service. This may well play a role in project proponents being interested in partnering with TGI in the upgrading of raw biogas, and TGI has anecdotal evidence from project proponents to suggest this has been the case already. If this can be considered a competitive advantage, it is a fair one. TGI draws a distinction between a fair competitive advantage, such as the advantage that a company obtains through developing a strong reputation, and expertise in its field, and an unfair competitive advantage, such as the kind of advantage that can be achieved through predatory pricing, price discrimination, abuse of dominance, or deceptive trade practices. TGI will certainly not engage in any of the latter anti-competitive practices.

Ultimately, the extent to which TGI or any other company establishes itself as a successful supplier of biogas upgrading facilities will determine the level of success that TGI or any other company has in this marketplace. To the extent that TGI establishes itself as an "established and significant" supplier of upgrading facilities, it will enjoy the reputation that is achieved by any business through hard work and effort, and the competitive advantages that flow from these attributes. As stated above, there is nothing improper or contrary to the public interest in TGI enjoying such advantages over its competitors.

The only constraint that TGI is placing on third parties being involved in the upgrading process is that they are able to demonstrate they are capable of providing a reliable and safe source of biomethane. TGI, as the party selling biomethane service to customers, has a significant interest in ensuring that supply is not only safe, but consistent and reliable. These objectives are consistent with the Commission's mandate under the Utilities Commission Act. Apart from that requirement, which TGI believes is necessary to protect the interests of its customers, the owners of a biogas project are free to approach any other company in the business of upgrading biogas to investigate the opportunity for partnering in the venture in the hope of increasing the developer's profits beyond what it could make by selling raw biogas to TGI at a price acceptable to the Commission.

As the viability of the project contemplating the delivery of upgraded biomethane to TGI (as opposed to delivering raw biogas to TGI and having TGI upgrade it) will be a function of the proponent's cost of upgrading the biogas, the price for which a third party upgrader can provide upgrading service to the project proponent is going to be a significant factor in the proponent's selection of an upgrading partner. TGI's established reputation as a natural gas distribution company, or any future reputation as a supplier of biomethane, will not affect the cost at which it will provide upgrading facilities to the proponent. Assuming the project partner has decided it is prepared to own the upgrading assets, its decision as to a third party upgrader will come down to whether the cost and price structure of the third party upgrader can coexist within the financial parameters of the biogas project. This means that large, established manufacturers of biogas upgraders (of which there are several in existence) will potentially have an advantage over start ups. The savings on upgrading translates into additional profits for the project proponent.

The thought process described above that is undertaken by a project proponent to determine its most advantageous course of action will not be transparent to TGI or the Commission unless the Commission actively regulates the biogas project and upgrading (as these activities are themselves a public utility service). Rather, TGI negotiates the best arrangement it can in each case. The Commission adequately protects customers of TGI by setting the parameters for the cost of biomethane supply; contracts are approved by the Commission.

Over time, the development of a reliable supply of biomethane from a variety of sources (which TGI intends to pursue in a measured way based on demand for biomethane) means that TGI's market power vis-a-vis project proponents will increase. Savings in the upgrading costs that might otherwise have represented additional profits for the proponent can be translated into savings for TGI customers through TGI's negotiations with proponents. The Commission can influence this development by, for instance, regulating TGI's acquisition price parameters. At that point, those companies who can present the relevant expertise, financial stability, solid reputation as well as cost effective upgrading will emerge the most successful.

TGI believes that the Commission should be indifferent as to which companies provide the upgrading so long as customers are receiving a cost effective, reliable and safe supply of biomethane, TGI believes that it can assist in meeting the need for safe, reliable and cost effective biomethane. Were the Commission to take steps to exclude strong market participants like TGI from competing in the development of upgrading facilities, and leave behind those players who by virtue of their cost structure are less able to compete on price, it would ultimately be doing a disservice to both customers and project proponents.

22.0 Reference: Supply Side Business Model

Exhibit B-1, Section 8.2, Ownership Model, page 67

22.1 TGI states that: *"The Company's ownership model contemplates the partner retaining ownership and control over the equipment which digests organic material to create raw Biogas, as well as those assets required to collect raw Biogas from proposed collections such as digesters, landfills or sewage treatment facilities. Those assets require the largest investment and currently fall outside Terasen Gas' core expertise."*

Why is control of the upgrader process considered within Terasen Gas' expertise?

<u>Response:</u>

Please see TGI's response to BCUC IR 1.2.2.

22.2 Why is Terasen Gas Inc. assuming the risk of a stranded asset (upgrader) rather than offloading that risk to a non-regulated entity such as Terasen Energy Services?

<u>Response:</u>

TGI notes that there is minimal risk of stranding an upgrader as this question assumes, as these assets can be mounted onto skids and redeployed to another location, or sold, should the need arise.

The issue of whether an asset should be in a regulated entity is unrelated to the risk of stranding. It is an issue of whether the activity the asset is employed in can be properly classified as a regulated activity. For the reasons set out in TGI's response to BCUC IR 1.1.1., TES, or any other entity that provided upgrading services would be regulated.

Given that the activity is regulated and the benefits to gas customers of adding this product to the system (as outlined in the Application Section 1), the modest risk involved, and the administrative efficiencies of operating one utility instead of two for the same offering (e.g. avoiding issues like transfer pricing), TGI believes that its proposal to consolidate all of the regulated aspects of the offering in one entity is appropriate. Further discussion of the reasons why it is appropriate for TGI to operate the Green Gas program (instead of operating the program through a second regulated public utility) is found in TGI's response to BCUC IR 1.1.1.

22.3 TGI states that: *"The exception will be where the partner can be appropriately relied upon to provide this consistent supply of properly upgraded Biomethane."*

Since a partner can control the upgrader and associated facilities, how would the determination whether a partner should control this facility be made since it appears operational experience is necessary?

Response:

First and foremost, TGI needs to ensure that customer safety and asset protection are primary to any arrangement. In order to protect customers and assets, TGI would consider several elements to determine supplier competence before accepting biomethane from a partner-controlled upgrade plant.

1. Operations and Maintenance Experience: TGI would expect the same level of diligence in operating and maintaining upgrade equipment as it applies to all of the assets it controls. Practically, this means a potential partner would need to show that the upgrading equipment will be maintained and operated to the same standards TGI would apply. In the case where a partner may not have that expertise, it would be acceptable that the operation and maintenance was covered by a service and operating contract with a qualified contractor (most likely the equipment supplier). For example, in the case of the Catalyst Power Inc. Project, Catalyst Power has partnered with Flotech for maintenance and operational assistance of the biogas upgrade plant. Flotech, through its subsidiary, Greenlane Biogas, has delivered more than 20 biogas upgrading plants around the world in the last 20 years.

2. Project Delivery: It is possible that potential partners may either have experience in other jurisdictions with similar facilities or they may have experience developing other similar projects (such as electricity generation from biogas for example). If a partner has demonstrated an ability to deliver biogas projects successfully, TGI would look upon this favourably.

3. Proven ability to manage unusual situations: Does the potential partner have a proven ability to manage issues such as leaks or unexpected process conditions. Does the partner have the ability to respond to issues in a timely fashion from both a safety perspective and a reliability of supply perspective. By contracting with Flotech, Catalyst

will have proven operational experience to rely upon and a local office to respond to issues in the field quickly.

4. Financial Resources: It is possible that unforeseen events, such as equipment failures or system improvements, may require additional capital. Or, a situation may occur where an interruption in supply may result in a revenue shortfall for a period of time. Does the potential partner have the financial resources necessary to manage these situations?

5. Technical knowledge and resources: A potential partner may need to have a strong technical knowledge of gas and gas related equipment as well as a strong background in understanding the generation of biogas. This may require, for example, both knowledge of microbiology (in the case of a digester) and knowledge of mechanical engineering (pressure vessel requirements for biogas upgrading equipment). TGI would need to be satisfied that all of this expertise resides with or can be easily accessed by a potential partner. Again, in the case of Catalyst, PlanET (a well established digester company) has been contracted to develop appropriate design of equipment, consulting for digestion and construction expertise to ensure a successful project.

In the context of Biomethane supply (where TGI owns only interconnection facilities), TGI will consider all of these elements, and potentially others in the future, when making a determination about who may own the upgrading facilities.

23.0 Reference: Supply Side Business Model

Ex. B-1, Section 8.3.2, Terasen Gas Ownership and Control Over Upgrading Facilities, page 72

23.1 TGI States that: *"In summary, Terasen Gas must own and operate equipment to upgrade raw Biogas to Biomethane in order to ensure safe and reliable operation of Biomethane supply projects."*

Why would TGI simply not shut-off the biomethane supply if its monitoring equipment indicated that this supply was not meeting its specifications? If this were the case, what risk does TGI actually encounter if it does not own and operate upgrader equipment?

Response:

TGI will always ensure that biomethane meets the specifications necessary to ensure customer and asset safety. If biomethane does not meet specification, TGI will immediately shut off the biomethane supply. However, as stated in BCUC IR 1.2.2, TGI is also responsible to ensure that there is a reliable supply of biomethane to meet the needs of its customers.TGI believes that there is an increased risk to the *reliability* of supply when it does not own upgrade equipment. Managing this risk is critical during the early stages of the roll-out of this program because it could otherwise undermine consumer confidence. The Company believes that securing supply reliability early is a factor critical to the overall success of the Biomethane program. To clarify, it is important to recognize that TGI has sold a product to customers in the form of Biomethane. TGI therefore has an obligation to deliver this product as required. By owning the upgrading equipment, TGI has more control on meeting the obligations to our Biomethane customers. TGI retains more control over balancing supply with system capacity, supply quality and responsiveness to any concerns or issues.

If a third party owner of the upgrade facilities fails to operate equipment correctly or reliably and the supply is less than demand or off specification, TGI may be required to purchase carbon offsets to meet its obligations to customers. However, from the customer point of view, this issue does not originate with the third party supplier, but rather with TGI. TGI is responsible to the customer, but has much less control over the potential solution to the problem.

Further, TGI believes that having a role as an active owner and operator of biogas upgrading equipment will benefit the development of the biomethane market. TGI involvement will provide confidence for both potential suppliers of biogas and to customers who participate in the biogas program.

TGI's control of the upgrade equipment reduces the risk associated with the reliability of biomethane supply which will ultimately benefit customers. For this reason, it makes sense to limit third party ownership to circumstances where reliability concerns can be adequately addressed by potential partners.

23.2 Does Terasen Gas plan to have in place significant redundant upgrader equipment that other biogas/biomethane suppliers might not necessarily install in order to ensure reliability of supply?

Response:

In terms of technical reliability of the upgrading equipment owned by TGI, TGI plans to rely upon the expertise of equipment manufacturers to provide appropriate design redundancy to ensure reliability requirements set out in the individual contracts.

Technical redundancy of upgrade equipment alone will not ensure reliability of supply. Rather, a properly supported operating and maintenance plan and policies along with links to customer service will ultimately provide the best reliability of supply. TGI's discussion of reliability in the context of the ownership of upgrading also addresses the relative advantages of TGI owning and operating facilities as opposed to a partner. These concerns relate to the ability and willingness of the potential partner to operate the facilities in a manner that meets TGI's requirements so that TGI does not have to disrupt the flow of Biomethane on to the TGI system. The advantages of TGI owning upgrading equipment are discussed in BCUC IR 1.2.2 and the importance of TGIs obligation to biomethane customers is discussed in BCUC IR 1.23.1.

recognizes that customer adoption of these energy systems (for which EEC funding is provided) will, all else equal, reduce gas consumption and thus would represent a "substitution" in that context. The same is true for all of the EEC programs for which the Commission approved incentive funding in the recent EEC Decision.

However, EEC programs, like the provision of alternative energy solutions, support government energy and GHG policy objectives, while meeting the needs of customers. Those policy objectives have been specifically delineated, for instance, in "government's energy objectives", which the Commission must consider in the context of resource plans, expenditure schedules and CPCN applications. The Energy Policy speaks to both substitution and complementary use of energy with as referenced on Page 21 of the Energy Plan which states: “It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time… *Combinations* of alternative energy sources with natural gas….will promote energy efficiency”. Further information regarding how these alternative energy solutions support government policy is outlined, for example, at Part II Tab B of the Application.

24.3 Please explain how these types of natural gas substitutions use considered an essential service and hence should fall under the jurisdictions of a regulated utility.

Response:

The Act contemplates that an entity providing services in the nature of the alternative energy solutions (i.e. solar thermal, GSHP and District Energy Systems) is subject to regulation as a "public utility". The assumption implicit in the question that the Commission only regulates "essential services" is incorrect; TGI is not aware of any provision in the Act that would confer jurisdiction on the Commission to regulate only “essential services”.

Under the Act, the Commission's jurisdiction extends to a "public utility". The definition of "public utility" in the Act is, in part:

> **“"public utility"** means a person, or the person's lessee, trustee, receiver or liquidator, who owns or operates in British Columbia, equipment or facilities for (a) the **production**, generation, storage, **transmission, sale, delivery** or provision of electricity, natural gas, steam or **any other agent for the production of** light, **heat**, cold or power **to or for the public or a corporation for compensation**…" [Emphasis added.]

The alternative energy solutions such as solar thermal, GSHP, and DES produce heat that is to be provided "to or for the public or a corporation for compensation". The provision of these alternative energy solutions to customers in the manner contemplated in this Application will be subject to Commission regulation regardless of the legal entity that provides these alternative energy solutions. Dockside Green is an example of a small regulated utility that employs a single District Energy System for the provision of heat energy, and is a good example of the type of project that TGI has in mind in pursuing these alternative energy solutions.

The *Utilities Commission Act* does not prohibit TGI from providing alternative energy solutions, or any other regulated service for that matter. Similarly, TGI is unaware of any provision in the Act that would confer jurisdiction on the Commission to prohibit TGI from pursuing particular alternative energy solutions. The Commission's core jurisdiction is with respect to rates charged by public utilities in respect of regulated services, and the management of the utility remains the responsibility of the utility management. The BC Court of Appeal has stated for instance (*British Columbia Hydro and Power Authority v. BC Utilities Commission* (1996), 20 BCLR (3d) 106 at 119):

> It is only under s.112 of the *Utilities Act* [the former entry, seizure and management provision] that the Commission is authorized to assume the management of a public utility. Otherwise the management of a public utility remains the responsibility of those who by statute or the incorporating instruments are charged with that responsibility.

Rates – in this case, the gas rates and the rates payable by alternative energy customers - must be just and reasonable and not unduly discriminatory. The Commission, in determining just and reasonable rates, must determine the appropriate allocation of costs as between gas customers and customers of the alternative energy solutions. The proposed economic tests are an efficient means of addressing cost allocation issues, modeled on the existing Main Extension (MX) test and previously accepted cost of service tests. The approval of economic tests will facilitate TGI negotiating just and reasonable alternative energy rates in the form of individual contracts entered into with individual customers and filed with the Commission. It is important to note, however, that with or without the economic tests for which approval is being sought, TGI believes that it would be possible for TGI to file individual contracts with customers for the provision of alternative energy solutions for approval as a rate. While this approach is equally valid and permissible under the Act, it is a less efficient approach because it would be necessary for the Commission, intervenors and TGI to address cost allocation issues as between the new customer and other (gas) customer's classes each time a contract is filed.

26.0 Reference: Biomethane Supply Projects Included in this Application

Exhibit B-1, Section 9.2.1, Overview, page 84

26.1 TGI states that (page 84): *"The CSRD indicated an interest in a beneficial use for landfill gas in response to the Terasen Gas Request for Expressions of Interest ("RFEOI") in 2009."*

Did TGI investigate whether other private parties were willing to finance the collection facilities and digester where TGI does not have expertise? Did TGI investigate whether it could attract suitable partners to develop the upgrading facilities?

Response:

To clarify there is no digester involved in the CSRD project. Essentially the landfill acts as a digester in this type of project. CSRD provided a submission to TGI that indicated preliminary feasibility for a project at the landfill which included cost estimates for the landfill collection facilities and the upgrade equipment.

In early discussions, CSRD indicated a preference for working with TGI. TGI responded to the wishes of CSRD and indicated willingness to participate in the project by investing in assets. CSRD indicated a preference for working with TGI for several reasons:

1. Financial: CSRD indicated a desire to reduce the capital required to develop a solution at the landfill that provided maximum environment and economic benefits. The avoided cost of the upgrading equipment was a direct savings to taxpayers in the region.

2. Trust: CSRD sees TGI as a trusted operator. CSRD indicated confidence that TGI would operate the system in a safe, reliable manner and invest appropriate resources in maintenance of the equipment.

3. Transparency: CSRD indicated a preference for working with a regulated utility that is subject to active oversight by the Commission.

4. Longevity: CSRD is making a significant investment in gas collection assets and therefore wanted a long term contract to maximize the use of the capital invested over a long period of time. CSRD indicated that because TGI is a stable entity with an assumed long-term health, there is reduced risk associated with benefitting from this project for many years in the future.

5. Access to customer: CSRD recognized that TGI could provide a link between the supply of biomethane and customers, which would ultimately increase the likelihood of ongoing revenue from the biogas at the landfill.

6. Simplicity: CSRD preferred to develop a single contract with competent partner over a three-way or indirect contract.

TGI developed a contract with the wishes of CSRD in mind, and therefore did not investigate using another private party to either invest in or operate the upgrade facilities.

In general, TGI is willing to invest in upgrading facilities when the partner does not want to undertake this investment themselves and/or does not have the capacity or experience to operate this type of equipment. Further it would be the suppliers' prerogative as the project owner to seek out a potential partner if the preference was to enter into a supply agreement with TGI for biomethane, as Catalyst did, and present a viable proposal to TGI. In addition, any commercial transaction is further complicated by introducing a third party into the transaction to invest into the upgrading facilities as TGI involvement is required to ultimately connect to the system.

TGI believes that either:

1. A supplier can approach TGI with a willingness to provide biomethane to TGI and TGI must ensure that the supplier can perform this function; or

2. TGI and a potential supplier can come to an agreement where TGI owns and operates upgrading equipment with the supplier providing raw biogas.

In preliminary discussions with suppliers, TGI will generally make them aware where there appears to be a lack of knowledge of the various options and possible financing routes for various aspects of the project. Ultimately, it is the supplier's decision to determine which approach to proceed with, assuming the project supplier can meet the requirements of TGI for them to own and operate the upgrading facilities, as the supplier is the project owner, not TGI.

26.2 What is TGI's position, if the Commission required TGI in future projects to investigate whether partners were willing to invest in the collection network, digester and upgrading facilities in all future projects and TGI would only be involved in these projects if other partners could not be found.

Response:

As stated in the Application in Section 8.3.1, TGI would not consider owning the collection network or digester. The issue of ownership relates only to the upgrading facilities. There are some key reasons why the proposed approach, as it relates to the upgrading facilities, is undesirable.

First, from the standpoint of reliability of supply, TGI has stated several reasons that it is important to own and operate upgrade equipment (please refer to BCUC IR 1.2.2). TGI believes that it is in the best interests of customers to place the reliability concerns identified in other responses above an inflexible policy of having TGI avoid ownership unless absolutely necessary. The quality of the partner should be considered (factors TGI would consider are outlined in BCUC IR 1.22.3). If the proponent identifies a qualified partner to undertake the upgrading, TGI has already indicated it is open to that approach. The Catalyst project is an example of this.

Second, there is a practical business issue with the approach identified. Project proponents, and not TGI, will make the determination based on their own business considerations whether to develop projects. A Commission policy such as that identified in the question may thus impede the development of supply in two ways: (a) project proponents may not be in a position to proceed without TGI's involvement, due to financing issues etc. and (b) may be unwilling to go into business with an upgrading partner about whom they, or their financial backers, have reservations or who cannot accommodate their expectation of return on investment.

Third, TGI believes that this policy will have a perverse impact on the cost of supply in the long term. Customers will benefit in the long term from wider availability of supply, not by raising obstacles to the cost effective development of supply.

Fourth, the risk of stranding, which this hypothetical policy would seem to be directed at addressing, is small. Moreover, the risk relates almost entirely to the interconnection facilities, as the upgrading equipment can be moved and reused. The small stranding risk relating to the interconnection facilities will exist regardless of who owns the upgrading equipment.

TGI believes that the best approach to meet the needs of customers is an approach that allows TGI to own and operate upgrade equipment while also allowing biomethane suppliers to contract with TGI provided they can meet required criteria.

27.0 Reference: Biomethane Supply Projects Included in this Application

Exhibit B-1, Section 9.2.3, Description of Facilities Addition, page 87

27.1 TGI states that (page 87): *"As the assurance … this additional monitoring equipment might be able to be removed from the site and redeployed to another Biogas project once this flow rate is confirmed."* TGI also states that: *"As with the monitoring equipment, the gas control connection may be able to be removed and redeployed to another start-up Biogas project as confidence in the quality and consistency of Biogas from the CSRD project grows."*

27.2 What measures has TGI taken to permit the redeployment of equipment to another biogas project?

Response:

TGI will respond to this question keeping in mind that in the case of CSRD, TGI is investing in both interconnecting facilities and an upgrading plant.

In the case of the interconnection facilities (which includes metering, monitoring, gas control equipment, odourant) TGI has intentionally designed equipment to maximize the potential for redeployment. Specifically this includes features such as:

1. Design piping and valve sizing covers a range of gas flows.
2. Equipment layout is similar to typical TGI facilities.
3. Equipment is mounted together on a single skid. This allows for the entire assembly to be moved without breaking a lot of connections.
4. More sensitive equipment such as the gas chromatograph and communications equipment is situated to avoid exposure to the weather and therefore increase life.

See below how the equipment (including building) is mounted together on a single skid at the Catalyst Power Inc. site.

Catalyst interconnection equipment

In the case of the CSRD upgrade plant, TGI has contracted for a packaged upgrade plant that is mounted together on a single skid. The manufacturer will ensure that the entire upgrade plant is packaged to be reliably redeployed if required in a similar fashion to the TGI interconnection equipment on the Catalyst project. At this point in time, the plant is in a design phase and therefore no photo is available.

TGI is confident that the design and fabrication of both the above ground interconnection facilities and upgrade equipment can be redeployed if necessary.

mainland customer, this will result in an incremental bill impact of **38** cents annually as discussed in Section 10.5 of the Application.

Terasen Gas believes that allocating costs on the principled basis outlined in the Application is appropriate and should be adopted.

64.2 In the case of Salmon Arm, the Upgrader is estimated to cost $1.6 million. Please provide a detailed estimate of the component costs including labour and the construction schedule.

Response:

TGI received a fixed price quotation for the upgrader (upgrade plant) from Xebec Inc. The upgrade plant will be delivered as a self-contained processing plant designed and manufactured by Xebec. Because the plant is being supplied as a single piece of equipment, the breakdown of costs is approximate. In addition, Xebec will be responsible for commissioning of the plant on-site.

A high-level breakdown of the plant costs provided by Xebec is provided below.

Item		
Plant Engineering	10%	$ 135,000
Plant Equipment	55%	$ 742,500
Plant Piping & Instrumentation	14%	$ 189,000
Plant Integration & Controls	14%	$ 189,000
Project Management	5%	$ 67,500
Misc.	2%	$ 27,000
Subtotal - Upgrade Plant		**$ 1,350,000**
Commissinong		$ 85,000
Contingency		$ 186,810
Total		**$ 1,621,810**
Less ICE contribution		**$ 315,600**
Less BCBN Grant		**$ 200,000**
Less ICE contribution transferred (Opening Balance)		**$ 50,400**
Total		**$ 1,055,810**

As discussed previously in BCUC IR 1.28.1 and restated here, TGI has also secured government grants totalling $515,600 which will go directly against the costs of the upgrade plant. In addition the Company has also already received $50,400 contribution that was transferred from the Lions Gate project that did not go ahead. Once the government grant amounts are subtracted in, the total estimated cost of the upgrade plant is $1,055,810. In the "J-2" financial schedules the plant asset costs and the contribution are shown separately.

Contingency costs are included to account for foreseen costs that may be associated with coordinating the upgrader design & installation with both TGI and CSRD. It includes, but is not necessarily limited to the following:

1. Interface engineering – mechanical, electrical, drain lines
2. Weather related challenges – snow or cold weather costs such as snow removal from equipment,
3. Customization of plant controls to TGI – programming or adjustment to control algorithms to better suit TGI requirements

The detailed schedule is currently being developed and as such, the timeline may change. However, at the time of filing, a high level preliminary schedule was developed specifically for the delivery of the upgrader plant. The milestones for the schedule at the time of filing are provided below.

Item	% Cost	Milestone Date
Placement of PO with Xebec	5%	31-Mar-10
Long Lead Equipment Order	25%	30-Jun-10
Process Design - Complete	25%	31-Jul-10
Final Design - Fabrication Drawings Complete	25%	30-Sep-10
Plant Fabrication	10%	15-Nov-10
Final Commissioning	10%	30-Dec-10

64.3 Prior to construction of the Salmon Arm Upgrader, did TGI attempt to solicit private interest groups that might be willing to construct the Upgrader? If so, how was this done? Why is Terasen Energy Services not building the Upgrader ?

Response:

It is understood that "soliciting private interest groups willing to construct the upgrader" means actively seeking out third parties who would be interested in owning and operating the upgrading equipment for the Salmon Arm Project. For the reasons set out below, TGI did not actively seek out a third party partner to own and operate the upgrading facilities for the Salmon Arm Project.

As set out in the Application, TGI's ownership model contemplates TGI owing and operating the upgrading facilities for these projects, so that it can ensure that the process is undertaken in a manner that produces a consistent and reliable supply of biomethane. The exception will be where a partner can be appropriately relied upon to provide a consistent supply of upgrade biomethane.

Whether the exception to TGI's preferred ownership model for upgrading equipment will be considered for a given project will be driven by the supplier's preferences. Suppliers who wish to either own the upgrading equipment themselves, or partner with an entity other than TGI, can propose this model to TGI. If the proposed supplier or its partner meets TGI's financial and technical standards, then TGI will permit the supplier/partner to own and operate the upgrading facilities. In the case of suppliers who do not express a desire to own and operate upgrading equipment (or partner with a third party), TGI's preferred ownership model will be used. TGI does not plan to actively solicit third parties to own and operate upgrading equipment for any of these projects. Using this approach provides potential suppliers with flexibility in moving their projects forward and allows them to determine the business model that is best suited to their needs.

In the case of the Salmon Arm Project, a significant consideration was the wishes of CSRD. It was clear early in discussions that CSRD was not interested in owning and operating upgrading equipment. CSRD has few resources to apply to a project at the landfill. The current CSRD resources are dedicated to typical daily landfill operations and it was expressed that it was important to keep these resources focussed on the activities best suited for the staff. Therefore, CSRD directly approached TGI to own the upgrading equipment.

It was also clear that CSRD was interested in partnering with TGI as this was in alignment with CSRD's mandate to have transparent operations with the public.

Furthermore, it was believed by CSRD and TGI that a third party would have complicated operational arrangements specifically in regard to optimizing biogas production, which would be to the detriment of both parties. In an effort to increase the potential revenue for the CSRD, it was requested that the project move as quickly as possible to ensure as early a start date as possible. TGI believes that these concerns will arise with most suppliers and with respect to most projects.

For these reasons, TGI did not actively seek out a third party partner to own and operate the upgrarding facilities for the Salmon Arm Project. If TES were to build the upgrading facility for the Salmon Arm Project, it would be subject to regulation in the same way as TGI. TGI considered that it was most effective to operate biogas projects using one utility rather than two utilities. See also TGI's response to BCUC IR 1.1.1.

65.0 Reference: Knowledge Tech Consulting Inc.

Exhibit B-1, Appendix K

65.1 On January 20, 2010 TGI engaged Knowledge Tech to perform services and below is an excerpt from the Application:

Statement of Work

Janice will work on the BioGas project, as part of the BCUC Application Team, in the role of System Impact Analyst.

She will be responsible for documenting the changes to business processes, system impacts and working with IT resources to determine cost estimates for any system impacts.

The timeframe for this work is from January 4, 2010 to March 31, 2010. The objective within this timeframe will be for her to finalize the cost estimates by the end of February. As such, it is likely that she will contribute more time in the January/February timeframe, with less time required in March for additional advice, clarification of costs and any revisions that may be necessary.

65.1.1 Was it decided by January 20, 2010 that TGI would make an application for biogas?

Response:

This response addresses BCUC IR's 1.65.1.2, 1.65.1.3, 1.65.1.4, 1.65.2, 1.65.3 & 1.65.7.

As discussed in the response to BCUC IR 1.43.2.4, in TGI's 2010-2011Revenue Requirement Application that was submitted June 15, 2009, TGI proposed the development of biogas supply as a pilot and indicated that it would be pursuing the development of a Green Gas marketing plan in parallel with the supply development proposal that was included in that Application. While we intended to proceed as quickly as possible with the development of a targeted Biomethane sales offering, the Company indicated that an offering of this nature could not be fully developed and brought forward before the end of 2009. TGI held an introductory meeting with Knowledge Tech Consulting in November 2009, i.e. during the course of the RRA proceeding in which TGI had proposed a Biomethane pilot project, with onsite personnel from Knowledge Tech to outline a possible business opportunity in regards to how a Green Gas rate could be offered for different types of program options. At this meeting the various platforms TGI could utilize to support a Green Gas offering from a system, process and IT perspective were discussed.

It was decided in late November 2009 with the approval of the Negotiated Settlement Agreement in the TGI 2010 -2011 Revenue Requirement and Delivery Rates Application by Commission Order No. G-141-09, that TGI would make a vertically integrated application for biogas to include the supply as well as the end to end business model and type of customer offering. Therefore, in December 2009, TGI requested a Knowledge Tech Analyst be assigned to evaluate current and past billing system platforms and solutions such as Stable Rate, Customer Choice and the Company's current Standard Rate to determine changes to business processes, system impacts and other IT items. The objective was to help determine the best billing solution for a Green Gas offering to customers, no matter what the offering was going to be. This work was necessary to allow TGI to include cost information in the planned Biogas application. Knowledge Tech did not provide specific analysis of alternative green energy programs such as carbon offsets. They provided insight into how past and current product offerings were done from an IT and process point of view.

A Project Scope meeting was held January 4, 2010 with the assigned Knowledge Tech Analyst to review project requirements. It was not yet determined at this time what type of product offering TGI would have, as it was slightly prior to the availability of the detailed residential and commercial TNS survey results (available January 5, 2010 & February 5, 2010) but TGI knew there was work to be done to pull together the end to end business model to support a Green Gas offering to customers no matter what product offering. Much of the analysis could begin in terms of system infrastructure review, billing platforms and tracking prior to having the exact type of product offering finalized. Then, based on the TNS research findings TGI put forth a product offering for which Knowledge Tech determined the solution from an IT and billing perspective.

TGI has used and continues to use Knowledge Tech Consulting for project work from time to time across various departments within the Company. They are familiar with the Company and our internal processes. For example, Knowledge Tech has done and continues to do work around the Company's Forecasting Information System. Therefore, the engagement process did not require a formal request for proposal. Rather, as a result of the project scope meeting, Knowledge Tech provided a Scope of Work (Appendix K). TGI accepted the Scope of Work and issued a Purchase Order to Knowledge Tech January 29, 2010 to cover the consulting services from January 4, 2010 to March 31, 2010.

From January 4, 2010 to March 25, 2010, Knowledge Tech researched the best solution to implement the product offering from an IT, process and billing point of view which then focused in on a renewable energy program after the residential research findings were made available January 5, 2010 and confirmed in the commercial findings February 5, 2010 favouring an energy-based program that offered a % blend of Biomethane. Knowledge Tech did not just do a specific analysis of a 10% user pay premium as the proposed business model supported multiple blends and the % premium is simply a result of the difference between the current commodity price of natural gas and Biomethane. As a 10% blend was the most popular option selected by respondents in the surveys, it was referenced as an example in much of Knowledge Tech's work. Further work however was required from TGI to determine the impact of offering the product offering to different rate classes and different rate blends (i.e. a 10% and 20% green offering) at the same time. This resulted in an estimated additional cost of $50,000 per each additional blend from Customer Works Ltd Partnership. If the product offering were to be rolled out to commercial and residential customers at the same time, TGI estimated that additional customer education funds of approximately $80,000 would be required in addition to the $50,000 in incremental CWLP charges for each additional blend.

As discussed in Section 10.3 of the Application, as a result of this work, Knowledge Tech provided a final Biogas Cost summary report March 5, 2010 as discussed in the response to BCUC IR 1.65.6 and finalized draft business impact documents and process maps for the Company to work off of for the implementation of a Green Gas program for the billing, tracking, reporting and management of a program by March 25, 2010.

65.1.2 Did Knowledge Tech evaluate the changes to business processes, system impacts and other IT items assuming that a 10% user pay premium program would be implemented?

Response:

Please refer to the response to BCUC IR 1.65.1.1.

65.1.3 Did Knowledge Tech provide analysis of alternative green energy programs such as carbon offsets? If yes, what percentage of time (relative to the entire project) was spent investigating such options?

Response:

Please refer to the response to BCUC IR 1.65.1.1.

65.1.4 Did Knowledge Tech conduct analysis of offering multiple user pay rates (such as 5%, 20% or 30%) during their engagement? If yes, what percentage of time (relative to the entire project) was spent investigating such options?

Response:

Please refer to the response to BCUC IR 1.65.1.1.

1.0 Reference: Exhibit B-1, Section 1.1, page 1

1.1 Does TGI envision partnering for Biogas supply with any entity that is affiliated or related to TGI or any entity in which TGI has an interest?

Response:

No. TGI will either invest directly in projects, or partner with unrelated third parties to facilitate the development of biomethane supply to meet the demands of our customers.

1.2 Please compare the relative financial risks and rewards that the shareholder would have if the green offering were made by an unregulated affiliate rather than by the regulated utility.

Response:

The offering is, by definition, a regulated offering. Please see TGI's response to BCUC IR 1.1.1 addressing the relative financial risks and rewards of TGI owning and operating the upgrading assets, relative to another regulated entity, whether a TGI affiliate or otherwise.

In circumstances where TGI owns the upgrading facilities, the risk of stranding is relatively small because the upgrading facilities can be moved. The stranding risk arises from the relatively modest cost of the interconnection facilities, and this risk exists regardless of who owns the upgrading facilities.

To the extent that there is a cost risk in respect of the upgrading facilities, it is managed through the use of fixed price contracts for equipment, and other means identified in the response to sections 9.2.7, 9.3.6, and 11 of the Application. The residual cost risk is shared between customers and the shareholder as follows: the customers bear the risk of prudently incurred costs being higher than budgeted, and the shareholder bears the risk of non-recovery of imprudently incurred costs.

The rate of return on equity on TGI-owned upgrading facilities is that rate of return that has been established by the Commission for TGI as a whole.

The shareholder of a third party or affiliate owning the upgrading assets bears the entire (albeit modest) risk of stranding and cost overruns. It also has only one customer - TGI. This potentially increased business risk could conceivably result in the entity requiring a higher return on its investment than the regulated rate of return accorded to TGI. This higher return would be factored into the price of biomethane sold to the Company, driving the cost of biomethane upwards. The higher cost is passed on to customers through higher Green Gas offering rates.

In light of the relatively modest stranding and cost risk with upgrading facilities, and the risk adjusted return required by any owner of the upgrading facilities, TGI believes that a desire to mitigate this relatively modest risk should not be driving the decision regarding who owns the upgrading facilities. Rather, customers are best served when the operator of the upgrading facilities is capable of delivering a safe, reliable and cost effective supply of biomethane. TGI is capable of doing so, and there will be instances where third parties are also capable of doing so. The model should be left flexible so as to allow room for consideration of commercial realities in particular circumstances, which may make one or the other model the appropriate choice for a given project.

3. Reference: Exhibit B-1, Page 6

> As will be demonstrated in Section 3 of this Application, Terasen Gas customers want to purchase and consume Biomethane. Terasen Gas is submitting this Application to ensure that this demand is met safely, reliably and economically. Owning and operating the required

3.1. Isn't this program also vital to all existing customers to help change the perception risk by demonstrating that the natural gas product can be a renewable supply source of heat?

Response:

Agreed.

Terasen Gas believes that its customers will benefit from the biomethane product offering, which is a renewable energy source, with its production and consumption being carbon-neutral, and therefore resulting in a net reduction in GHG emissions. If the Application is approved by the Commission, the addition of biomethane as a renewable natural gas product will further highlight, along with TGI's other energy efficiency and green initiatives (such as alternative energy developments), that the natural gas system and infrastructure can be used as part of the solution to help customers reduce their emissions and do their part in addressing climate change. This new product offering will help to educate energy consumers in BC that other more practical and efficient solutions than an all electricity solution exist and should be considered. Success in the Company's suite of energy efficiency and alternative energy initiatives, including the biomethane initiative is vital to the long term health of TGI and its natural gas infrastructure and its customers.

3.2. Isn't it vital that Terasen have a significant & flexible willingness to be in an ownership position for the purpose of development of the market and for the perception reason?

Response:

Agreed.

TGI has a significant leadership role to play in facilitating the development of a biogas or biomethane market in BC. The main alternative to upgrading biogas for pipeline injection, other than simple flaring, is to produce electricity. TGI believes that, with limited exceptions, producing electricity from biogas is an inefficient use of the resource when compared with upgrading to biomethane for pipeline injection. If TGI was to adopt a passive or do-nothing approach with respect to biogas the default response would be to generate electricity and the opportunity to utilize available biogas resources in the province in the most efficient manner would be lost.

TGI has consulted with industry over the past two years both more formally through its RFEOI process and informally through discussions with market participants both locally and in other jurisdictions. TGI believes that in order for the industry to develop in a smaller market like BC, the utility must take a leadership role and be prepared to be flexible in its approach.

The business model that is outlined within the Application is flexible. We have outlined two ownership supply models within the Application, including the possibility of third parties providing both biogas collection and upgrading service if certain conditions can be met by the supplier. This should promote competition and supply development competition among suppliers to meet the demand of our customers.

3.3. Isn't it also true that development of this potential in BC needs the kind of leadership, which Terasen can provide or its development may not be as robust as is needed to meet provincial GHG objectives?

<u>Response:</u>

To achieve the aggressive provincial GHG reduction targets by 2020, TGI will need to play a prominent role in providing new products and services to energy consumers in BC that assist in meeting these goals.

TGI estimates that about 15 to 17 percent of BC's total emissions came from the consumption of natural gas in 2007. Given that the emission output from the electricity sector is small, and the emission from the upstream oil and natural gas production is expected to grow with the discovery of the Horn River shale gas play, it is expected that the transportation and residential and commercial sectors have the greatest potential for GHG reductions within the Province.

TGI has played a leadership role to date in outlining and implementing alternative energy strategies, including the use of biomethane, that can help make use of the existing natural gas infrastructure, while helping customers reduce their carbon intensity. TGI believes that its participation in the market as outlined in the Application will add simplicity and certainty to the process of developing supply resources. Further, that without this leadership, the GHG emission reductions achieved from this resource will be diminished as biogas resources will be used

4. Reference: Exhibit B-1, Page 6

> As will be demonstrated in Section 3 of this Application, Terasen Gas customers want to purchase and consume Biomethane. Terasen Gas is submitting this Application to ensure that this demand is met safely, reliably and economically. Owning and operating the required

4.1. Why would the company be trying to attract partners to own and operate biogas upgrading facilities?

Response:

TGI believes that neither the market for biomethane nor the supply of biomethane is mature enough to formalize a single approach to the supply. Therefore, a flexible approach to operating and ownership arrangements will provide the most benefit for customers and suppliers.

However, TGI believes that in order to ensure customers have a safe, reliable supply of biomethane, the best approach is to own upgrading facilities. As discussed in BCUC IR 1.2.2, there are several reasons for this model and Terasen Gas has the experience and competence to successfully manage these assets.

TGI does not see any benefit in the activity of attracting partners to own and operate upgrading facilities as a goal unto itself. The best way to benefit the market is to attract partners in the development of the raw biogas resource which will involve a variety of differing competencies. This will benefit the market and ultimately customers because having multiple approaches will allow TGI to optimize supply and demand matching while at the same time focusing on its areas of strength – upgrading and delivery of biomethane.

4.2. Isn't it only sufficient that if independent suppliers want to get into the business that Terasen provide standards, equal to those standards Terasen meets, and have methods of monitoring and ensuring performance to standards?

Response:

Methods of monitoring and securing contractual obligations are a precondition to having third parties engage in upgrading, but it is preferable if those preconditions are supported by the considerations that suggest commitments will be met without resorting to enforcement of contractual obligations. Hence, in the case where an independent supplier can also demonstrate reliability (financial, technical and security of supply) Terasen Gas is willing to accept biomethane from this supplier provided the price is competitive. In this case, as stated in Section 8.3.3 of the Application and restated here, Terasen Gas intends to ensure measuring and monitoring is done for the project. At this early stage of market development, a mechanistic standards based approach is not possible but in the long run Terasen Gas believes that this will likely evolve as the market grows.

At no time will Terasen Gas risk the safety of customers or integrity of existing assets in order to build supply volumes by relying on independent suppliers.

5. Reference: Exhibit B-1, Page 7

removal of non-combustible gas which will increase the heating value of the gas. Elements such as N_2, O_2 and H_2 are monitored to ensure that, if they are present, they are present in such small amounts that they not impact the safety or heating value of the gas. Other contaminants such as H_2S, NH_3, siloxanes and dust are filtered out to ensure that the end product is clean and safe for pipeline injection. For the purpose of this Application, the purification process will be referred to as "upgrading". Once Biogas has been upgraded, it is safely interchangeable with natural gas in the existing distribution and transmission system.

5.1. In the upgrading process are any of the by-products useable and saleable or are they all wasted?

Response:

TGI believes that there may be opportunity to take advantage of certain waste products including heat from the upgrade process in certain projects.

The upgrade process may vary according to the particular choice of technology used in a given application and therefore the waste products may vary in amount and form. For an overview of some of the best known technology including that used in the first two biogas projects in BC, see Section 2.5 of the Application.

The most likely sources of useful waste products are heat generated from the process and carbon dioxide (CO_2). There are efforts around the world to look for ways to better use these two waste products, but one of the most promising applications is in agriculture. A good example of a use of waste heat and CO_2 in a greenhouse to enhance growing is the WarmCO2 project in the Netherlands (www.warmco.nl).

TGI believes that there is opportunity in the future to take advantage of waste heat and CO_2 from upgrading equipment making it an even more attractive option as a source of renewable energy.

In another example, it is proposed that waste water from a biogas upgrade plant get used to aid in the post-composting process. The material would then be screened and bagged to sell as a product.

In addition, on the raw biogas supply side, there is opportunity to take advantage of waste products in some cases. For example, in the case of a digester, the remaining undigested solids can be used for animal bedding reducing the need for the import of new materials to a farm. Similarly, the leftover liquids can be used as a fertilizer for fields.

Overall, there are opportunities to take advantage of by-products in certain projects.

1.0 Reference: Biogas Upgrading

Exhibit B-3, BCUC 1.1.1, p.1-3

Hartland Landfill Beneficial Use of Landfill Gas (Hartland Landfill), slide 17

http://www.crd.bc.ca/waste/hartland/documents/landfill_gas.pdf

TGI states: *"The British Columbia Oil and Gas Commission and the National Energy Board regulate the extraction, production and transportation of natural gas through processing facilities and gas pipelines to a public utility's gas distribution main. From that point onward natural gas is regulated by the Commission."* (Exhibit B-3, BCUC 1.1.1)

1.1 Given that biogas upgrading facilities and the upgrading process are upstream of the public utility's gas distribution main, would it be appropriate for the Commission to develop a separate methodology for analyzing biogas upgrading facilities? Please explain why or why not?

Response:

The processes in the Act applicable to "public utility" investments such as Biomethane upgrading assets (such processes could include a CPCN for larger projects, an optional expenditure schedule for smaller projects, and/or revenue requirements application) are equally applicable regardless of whether the asset in question is upstream or downstream of the gas distribution main. Put another way, the Act does not impose the distinction outlined in the question.

However, TGI recognizes that the upgrading assets are characterized by a relatively small capital investment that will typically fall below the CPCN threshold. TGI is also proposing that the Commission establish parameters for supply contracts for raw Biogas, and the supply cost must implicitly account for the cost of the upgrading facilities. These two factors suggest that a streamlined process, which focuses on whether the supply contract falls within the Commission's established parameters, is most efficient for addressing future supply projects. In section 8.4 of the Application TGI describes its proposal for how future projects should be assessed. For the reasons set out in TGI's response to BCUC IR 1.24.3, TGI believes that this approach is in the public interest and appropriate for analyzing future projects.

TGI states: *"If the Commission were to find that biogas upgrading facilities were not subject to the Act's provisions, the result would be a regulatory gap that would leave biogas upgrading facilities without an active regulator, which TGI submits would not be in* *the public interest. While there is legislation that governs certain aspects of the collection of gas from digesters and landfills, such as the Gas Safety Act and the Landfill Gas Management Regulation, there is no regulator, other than the Commission, with any jurisdiction to actively monitor and ensure the safe and also reliable operation of biogas upgrading facilities."* (Exhibit B-3, BCUC 1.1.1)

1.2 Please provide any legal decisions supporting Terasen's assertion that it is appropriate for a regulatory tribunal to expand its jurisdiction to fill "a regulatory gap."

Response:

This question appears to be based on a misunderstanding of TGI's position as described in its response to BCUC IR 1.1.1. For clarity, TGI believes that the Commission is a creature of statute and as such the scope of its jurisdiction is defined by the Act. The Commission cannot expand its jurisdiction beyond the "four corners" of the statute, whether to fill a perceived regulatory gap or otherwise.

TGI's position is that the upgrading of Biogas to Biomethane and the provision of Biomethane to customers by TGI is subject to Commission regulation because these activities are "public utility" services as defined in section 1 of the Act, not because there would otherwise be a "regulatory gap". In referencing a "regulatory gap", TGI was intending to point out that it made sense for the Legislature to have conferred this jurisdiction on the Commission as other regulation did not address matters such as reliability of supply.

1.3 Please provide excerpts of or links to the sections of the *Gas Safety Act* and the *Landfill Gas Management Regulation* that govern the collection of gas from digesters and landfills.

Response:

The Landfill Gas Management Regulation, B.C. Reg. 391/2008, a regulation under the Environmental Management Act, S.B.C. 2003, c. 53, is found at:

http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/28_391_2008

See the definition of "landfill gas management", which includes "collection of landfill gas". See also sections 2, 4, 7, 8, 9, 10, 11, and 12.

1.6 How does Terasen propose to deal with waste products from the biogas upgrading process?

Response:

Byproducts produced in solid form are small in quantity, non-hazardous and safe for landfilling.

Liquid condensate is sent to the landfill's water treatment system.

Gaseous byproducts (mainly CO2) are handled in accordance with current landfill practice and applicable regulations.

For some projects there may be opportunities for beneficial use for byproducts (CO2 for example). Terasen Gas will work with producers to identify and capture such opportunities.

1.6.1 Does the biogas upgrading process result in toxic by products? Please discuss. If yes, do the toxic by-products require special treatment, handling and storage?

Response:

Please see our response to BCUC IR 2.1.6.

TGI states: *"The analytical approach described above has been implicitly accepted by the Commission in other applications. In the Dockside Green Energy LLP Decision and Reconsideration, the Commission accepted that DGE's construction and operation of a biomass facility to provide hot water heating to the Dockside Green development was subject to the provisions of the Act. For the purposes of the application of the Act, there is no meaningful distinction between the Dockside Green biomass facility as a facility for generating an agent for the production of heat and biogas upgrading facilities that accomplish the same outcome."* (Exhibit B-3, BCUC 1.1.1)

1.7 For Dockside Green, were the risk of cost overruns and stranded assets borne by the ratepayers or the shareholder?

Response:

The purpose of BCUC IR 1.1.1 (Exhibit B-3), in the quoted reference above and the balance of the response, is to provide evidence and support for the fact that the Biogas agreements and the Biogas upgrading facilities included in the Application are regulated activities and assets under the Act. The reference to Dockside Green was in the context of using it as an example of a non-conventional energy system that is subject to BCUC regulation. BCUC IR 1.1.1 did not make any assertions about the treatment of costs or cost allocation approaches.

Nevertheless to respond to the question, the Commission decision in BCUC Order No. C-1-08 and the reconsideration decision in BCUC Order No. C-3-08 made a determination on the treatment of cost overrun and stranded asset risks for Dockside Green that is consistent with normal regulatory practice in BC. The following is an excerpt from Order C-1-08.

> ***"NOW THEREFORE** pursuant to Sections 45, 46, 59, 60 and 61 of the Utilities Commission Act (the "Act"), the*
>
> *Commission orders as follows:*
>
> *1. The Commission grants a CPCN to DGE for the construction and operation of a DES to provide hydronic energy service at Dockside Green as set out in the Application, subject to the following conditions:*
>
> *1.1 Any extraordinary capital expenditures or operating and maintenance expenses, natural gas and/or any other fuel commodity costs that are incremental to the costs included in the revenue requirements estimate presented in the Application and are required in order that the thermal energy generation system referred to as the Nexterra Plant fulfills the role described for it in the Application and supporting material, will not be included in DGE rate base and revenue requirements and will not be recovered in DGE customer rates.*
>
> *1.2 Any extraordinary capital expenditures or operating and maintenance expenses, natural gas and/or any other fuel commodity costs that are incremental to the costs included in the revenue requirements estimate presented in the Application and are required in order to obtain, process, handle or replace the fuel source for the district energy system, including the cost of gas that is used because wood supply is not available or the cost of wood supply to the extent it exceeds the price set out in the Binding Letter of Intent with Three Point Properties LLP that is Attachment 7.1 in Exhibit B-2, will not be included in the DGE rate base and revenue requirements and will not be recovered in DGE customer rates.*

1.3 DGE has provided written confirmation to the Commission that it accepts the conditions to the CPCN, within 60 calendar days of the date of this Order.

2. If any of the conditions in the CPCN for the district energy system are not met, the CPCN is cancelled immediately."

The initial decision appears to put the risk of cost overruns on the shareholder. It did not directly speak to the stranding risk associated with investments falling within the scope of the CPCN approval, implicitly adopting the statutory allocation of risk. That allocation is that ratepayers bear the risk of stranding where the investment in the asset was prudent. The shareholder bears the risk of stranding where the investment was imprudent.

The Commission then reconsidered and issued Order C-3-08, addressing the risk of cost overruns. The following is an excerpt from that order:

*"**NOW THEREFORE** pursuant to Section 99 of the Act, the Commission orders that Commission Order No. C-1-08 is varied as follows:*

1. Sections 1.1, 1.2, 1.3 and 2 are removed.

2. Section 11 should be read so as to reflect the removal of the Commission determinations and directions set out in Sections 1.1, 1.2, 1.3 and 2 only and should include all other directions in the Reasons for Decision attached as Appendix A to Commission Order No. C-1-08 and Appendix A to this Order".

This reconsideration decision restores the appropriate balance of risk of cost overruns between customers and the shareholders. Dockside Green's request for reconsideration was based in large part on the fact that by disallowing cost overruns before any actually occurred the Commission was prejudging the overruns to be imprudent before the Dockside Green utility had an opportunity to defend them. The reconsideration decision allows the utility the opportunity to recover its prudently incurred costs including a fair return on investment. As such, the ratepayers bear the risk of prudently incurred costs that end up being stranded regardless of whether the costs exceed the budget, and the shareholder bears the risk for imprudently incurred investment in stranded assets.

1.8 For Dockside Green, were any of the costs related to program management and customer education borne by non-Dockside Green customers (i.e. Terasen's cost allocation proposal)?

19.0 Reference: Gas Collection Assets

Exhibit B-3, BCUC 1.26.2, p.89

TGI states: *"Fourth, the risk of stranding, which this hypothetical policy would seem to be directed at addressing, is small. Moreover, the risk relates almost entirely to the interconnection facilities, as the upgrading equipment can be moved and reused. The small stranding risk relating to the interconnection facilities will exist regardless of who owns the upgrading equipment."*

19.1 Please provide the estimated cost of moving upgrading equipment.

Response:

In order to estimate the costs TGI would consider decommissioning, transport, and re-commissioning. These costs will vary depending on the distance of the move and the particular upgrading technology used. As an example, an estimate of the decommissioning and recommissioning costs could be drawn from estimated commissioning and site costs of for the CSRD project. TGI estimates that decommissioning costs would range from $40,000 to $50,000 and that the CSRD commissioning costs of $85,000 (which includes a contingency) would apply for recommissioning as well. The relocation using truck transport, assuming a destination in the Lower Mainland for example, could be very roughly approximated at $15,000. These costs would combine to approximately $140,000 to $150,000 for relocation. TGI expects that such moving costs would be included in the cost of service for the new project in the same way that delivery and commissioning of new equipment would be.

25.0 Reference: EEC and Alternative Energy - Biogas

Part III, Section C, Tab 3 (p. 249)

"Over the two-year RRA period, we propose to expand the development of biogas capture and upgrading in BC in a Pilot Phase of limited scope."

25.1 What is the estimated capital required for the Biogas pilot phase as discussed on pages 249-259 of the Application?

Response:

Reaching the 0.5 PJ per volume limit proposed for the biogas pilot phase is likely to involve somewhere between 5 and 10separate projects. As stated on page 257 of the Application, TGI has received nine submissions from a variety of raw biogas producers as part of the Biogas Request for Expressions of Interest ("RFEOI") and has been interacting with a number of other parties as well. It is important to note that the $15 per GJ cap on the pricing of upgraded biomethane in the pilot phase includes the costs of biogas upgrading, including the carrying costs of any capital invested.

There is a wide range of possible outcomes on how much capital will be spent to implement these projects. TGI anticipates it will own the biogas upgrading facilities at many of these projects but not all. Further there are many factors contributing to the possible capital costs at any particular project, including the proximity to TGI's system and local system capabilities, the expected throughput from the biogas project, the biogas upgrading technology adopted and various others. With the foregoing commentary as background, TGI believes a reasonable estimate of the range of capital investment over the course of this RRA is between $10 million and $20 million.

25.2 Why does TGI believe that the utility customers should fund the learning curve of the TGI employees?

Response:

Please see the response to BCUC IR 1.19.1.

25.3 Please advise whether this technology already present in the competitive market? Please provide all the reasons why TGI believe that Biogas should be considered under a regulated monopoly. Has TGI considered offering these Alternative Energy Extensions under an NRB i.e. TES? Please explain why TGI is in any better position to provide leadership and funding to Alternative Energy Extensions than Terasen Inc and TES?

Response:

This technology is already present in the U.S. market, but has not been implemented in the Canadian or B.C. market.

There are two main reasons why TGI believes that it is appropriate for TGI to pursue biogas upgrading opportunities, rather than deferring those opportunities to third parties.

First, TGI believes that there are some components of the capital investment required to connect biogas upgrading project to TGI's system that must be owned and operated by the regulated utility. These include the critical equipment and assets required to accurately test for gas quality and measure biogas gas volume as well as the connecting pipelines. TGI presently owns and operates these types of equipment to maintain safe and reliable service on its natural gas distribution system. The regulated utility possesses the skills and knowledge to operate such equipment.

Second, the pursuit of biogas opportunities by public utilities like TGI is consistent with provincial policy as expressed in the Energy Plan and legislated "government's energy objectives". For instance, the Energy Plan expressly contemplates public utilities taking a role in advancing alternative energy solutions:

> *"It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of alternative energy sources with natural gas include solar thermal and geothermal.* ***Working with*** *municipalities,* ***utilities*** *and other stakeholders the provincial government will promote energy efficiency and alternative energy systems, such as solar thermal and geothermal throughout the province."* [Emphasis added.]

This focus on utilities playing an integral role in the delivery of alternative energy solutions is reemphasized in the inclusion of "government's energy objectives" in the *Utilities Commission Act*. Biogas upgrading projects advanced by TGI would normally be subject to obtaining a CPCN (although the capital cost of individual biogas projects is expected to be below the proposed CPCN threshold and TGI is proposing an economic test to encourage administrative and regulatory efficiency), and "government's energy objectives" must be considered by the Commission with such projects. The "government's energy objectives" include two objectives that directly support a public utility like TGI advancing biogas upgrading: (i) "to encourage public utilities to use innovative energy technologies…that support energy conservation or efficiency or the use of clean or renewable sources of energy", and (ii) "to encourage public utilities to reduce greenhouse gas emissions". Biomethane is a clean and renewable source of energy provided through the development of innovative technology, and its use will encourage public utilities to reduce greenhouse gas emissions. TGI therefore believes that the Commission, through its regulation of TGI in the manner proposed in this Application, should be encouraging TGI to pursue it.

While "government's energy objectives" must be considered in conjunction with other factors, such as the impact on customer rates, TGI believes that it has appropriately addressed rate impact in its proposal. Some investment is required at the pilot phase, but the limited scope of the pilot means that the rate impact is negligible. At the same time, existing and future gas customers stand to benefit from a successful pilot. TGI has stated in the Application that its intention is to develop a "green" rate that recovers the incremental cost from customers with a desire to purchase biomethane. The availability of this "green" service has the potential to retain and attract customers that will contribute to the overall system costs for the benefit of all customers.

Thus, TGI believes in the circumstances that it has an important role in advancing the development of biogas and biogas upgrading as a resource in BC, and the proposal in the Application will help to advance that government-sanctioned objective.

36.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Part III, Section, Tab 5

Financial Treatment of Pilot Phase, page 259-261

36.1 TGI indicates that the company's investment in biogas upgrading equipment as well as O&M and other costs will be tracked in a separate account. Should not all costs including TGI staff time be tracked and assigned to this separate account for these projects as well?

Response:

There are two aspects to the staff time used for the development of biogas projects and supply, which will be discussed separately.

The first is identification of potential projects, their evaluation and investigations required to determine if the project or supply should be undertaken or acquired. These costs are marketing and sales costs related to providing customers with the service they request (which include both conventional gas and alternative energy) and, in addition, providing energy efficiency education and information. As such, these costs are no different than any other sales, marketing, and development costs that are spread across all customers and as such these costs should not be segregated. Also see TGI's response to BCUC IR 1.19.1.

The second aspect is project development. Once a specific biogas project has been identified and has received spending approval from TGI's capital planning committee (the Utility Operating Committee Capital Group) staff resources will be assigned to the project and tracked in the same way that other TGI projects are tracked. The tracking of these costs will allow them to be included in the project costs which, during the pilot phase, TGI proposes to include in the midstream cost recovery mechanism. If the pilot phase of TGI's biogas initiative were to indicate that fewer biogas projects are available than initial indications suggest, these staff resources would be directed to other TGI projects or initiatives.

36.2 Why is it necessary to build a pilot project when there are similar projects that already have been studied in different parts of the world?

Response:

Although biogas has successfully been captured and used to generate electricity or fire boilers for heating applications in numerous projects around the world, the upgrading of biogas to pipeline quality for injection into the distribution system is somewhat newer and has seen fewer applications within North America. While biogas upgrading for pipeline injection has been undertaken in enough circumstances to give TGI confidence that the practice can be successfully done, differences in pipeline quality standards, project specifics and cost implications of each individual project and location are sufficient to require TGI's own investigations into the viability of biogas for pipeline injection here in BC.

The pilot phase will help to establish whether or not an appropriate balance can be found (within a range of potential prices) between the price paid for upgraded biogas and the ability to incent developers to undertake biogas projects. An important aspect in the study of biogas projects is the ability of TGI to acquire a sufficient supply to create a green gas or carbon neutral market offering without paying more than a green electricity project equivalent using the same resource. The pilot phase will also improve the knowledge base of TGI staff in the planning, design and operation of upgrading equipment and potential equipment variations between upgrading projects. These initiatives are best undertaken as part of a pilot project or phase that examines project viability in circumstances specific to BC and the markets in which we operate.

The capture of useful bioenergy that would otherwise be wasted through biogas upgrading is of sufficient interest to the Province that it is referenced in the Bioenergy Strategy and two biogas upgrading projects were recipients of grants from the Innovative Clean Energy (ICE) Fund in the first round of grant awards. The pilot phase of TGI's biogas initiative is needed to advance early projects such as these in BC to kick start the development of biogas upgrading locally. A pilot phase is a logical initial stage in the sequential development of a new green supply resource and market.

36.3 How large is the "alternate energy" portfolio expected to be?

Response:

The question preamble is making reference to the Biogas portion of Section C, Tab 3; therefore, the response will discuss biogas as the alternative energy for which the question is intended.

While some studies have been done on total potential for biogas in BC, there are no definitive inventories available that can confirm the amount of biogas potential that exists throughout BC.

73.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-4, BCUC 1.36.1, p. 106

Biogas Pilot Phase Project

On page 106 it states: *"There are two aspects to the staff time used for the development of biogas projects and supply, which will be discussed separately. The first is identification of potential projects, their evaluation and investigations required to determine if the project or supply should be undertaken or acquired. These costs are marketing and sales costs related to providing customers with the service they request (which include both conventional gas and alternative energy) and, in addition, providing energy efficiency education and information. As such, these costs are no different than any other sales, marketing, and development costs that are spread across all customers and as such these costs should not be segregated."*

73.1 Please provide a forecast of the impact on the residential and commercial rates, of the sales and marketing costs associated with the development of biogas projects.

Response:

TGI does not have the sales and marketing costs for biogas projects separated from the sales and marketing costs for other alternative energy initiatives. A small number of staff (five or less) are spending a fraction of their time on biogas project investigation and sales and marketing efforts so the impact on residential and commercial rates is very small.

73.2 Are biogas "customers" TGI suppliers, customers or both (similar to electric net metering customers)?

Response:

TGI will have supply contracts with third parties for either raw biogas where TGI will do the upgrading or upgraded biomethane where a third party has already done the upgrading to pipeline quality gas. TGI considers these parties to be suppliers. Some of the third parties selling raw biogas to TGI may wish to become purchasers of upgraded biomethane but if that was the case it would be through special contract provisions with appropriate compensation in the supply agreement or through separate contractual arrangements (such as through the green rate offering, for example). In some cases, such as at sewage treatment plants, some of the raw biogas is burned for process heat, so the supply contract with TGI will only be for excess biogas.

TGI does not believe that the electricity net metering arrangements are a complete analogy for a biogas supplier producing upgraded biomethane in excess of its own natural gas consumption. This can be illustrated using a sewage treatment plant as an example. A sewage treatment plant may be able to burn raw biogas for process heat, but raw biogas cannot be used in furnaces to heat buildings where staff work. The sewage treatment plant may take natural gas service for the latter purpose. Thus, although it is a source of energy, the raw biogas is a different product than the upgraded biomethane. Another distinction between upgraded biomethane and natural gas is that the biomethane is a carbon-neutral green source of energy while the natural gas is not. In electricity net metering the self-generated electricity may or may not be from a green generation source and the self-generated power is indistinguishable from that coming in from the grid.

73.3 Please explain why identification and investigation of biogas projects (gas supply) are considered a customer service.

Response:

There are several reasons why the costs for the identification and investigation of biogas projects should be considered a customer service and why it is appropriate to keep these costs as part of O&M just as the costs for the identification and investigation of other alternative energy projects are also included in O&M.

Biogas is a new renewable source of alternative energy that will displace natural gas. Solar thermal and geo-exchange are also renewable sources of alternative energy that will displace or reduce natural gas use. The key difference between biogas and the other two alternative energy sources is that upgraded biogas will be distributed to end users through the natural gas distribution system while the other two will not.

The identification and investigation of biogas projects is an activity that will assist in meeting the government's climate change and energy objectives. As stated elsewhere, the province of BC has placed a high importance in these areas by setting binding targets for GHG reductions, by introducing changes to the Utilities Commission Act and developing several pieces of legislation aimed at achieving its objectives. TGI's identification and investigation of biogas projects represents a strand of its efforts to address these important matters on behalf of customers.

A third reason to keep the costs for identification and investigation of biogas projects in the O&M costs is that TGI is seeking in the RRA for a "pilot phase" in the development of this new renewable resource. When the development of biogas markets (for both supply and demand)

74.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Exhibit B-4, BCUC 1.36.2 and 1.36.4, pp.107-108

Biogas Pilot Project

74.1 If there are carbon credits attached to a project are they used to reduce overall customer rates?

Response:

Yes, TGI will include any benefits associated with carbon reduction to reduce the overall impact on customer rates during the pilot phase. This is described on page 261of the Application and demonstrated in Table C-3-11 (Exhibit B-1, page 256) where it is shown that the benefits of avoided carbon taxes will used to reduce the overall cost of the upgraded biomethane in customer rates.

74.2 If biogas projects or all alternative energy are considered as interruptible supply how is this consistent with the Essential Services Model ("ESM") whereby a gas seller is expected to deliver 100 percent of the normal annual demand as commodity, which in the case of TGI is through the CCRA?

Response:

As an initial point TGI does not consider all alternative energy to be interruptible supply. TGI will meet customer demands for heat energy at alternative energy developments with the same reliability that it meets customer demands for natural gas. Meeting this level of reliability will often involve natural gas backup, but customer demand will be met.

With respect to biogas, TGI adopted its proposed treatment of flowing the biomethane costs through the MCRA rather than the CCRA in order to avoid being inconsistent with the Essential Services Model. This was explained in the middle paragraph on page 261 of the Application which is quoted below for convenience:

> *"The main reasons for flowing biomethane costs and volumes through the MCRA are discussed below. The half petajoule maximum of biomethane under Pilot Phase represents less than 0.5 per cent of the overall MCRA purchases and will have only a small impact on the Midstream Cost Recovery Rate. There are many issues to understand and gain experience with during this Pilot Phase. For instance, it is expected that the load profile of upgraded biomethane coming from biogas production facilities into the TGI system will be fairly steady throughout the year but this is not known with*

certainty. The frequency of outages, the magnitude of process fluctuations and variations are all potential sources of variations in the amounts that will ultimately be received into the TGI distribution system. Further, the receipt point of biomethane on the TGI distribution system means that it would not be suitable to treat this supply in the same manner as the baseload supply of marketers or TGI. Commodity volumes provided by marketers or which flow through the CCRA are 100 per cent firm baseload supply that must be delivered in certain proportions at the Station 2, AECO and Sumas hubs. The biomethane volumes from any projects completed during the RRA period will differ in that they will be, in effect, interruptible supply."

The question also appears to imply that Biogas supply contracts and suppliers should be held to the same terms and conditions and delivery requirements as gas marketers supplying gas through the Essential Services Model ("ESM") of the Customer Choice program. TGI does not believe that this comparison is valid. Marketers supplying gas under the ESM operate under a very specific BCUC approved set of supply rules. In contrast, biogas supply contracts will be more similar to other commodity supply contracts TGI undertakes with upstream producers. In addition to the differences between biogas supply and gas delivered by marketers under the ESM as identified in the quoted paragraph above, TGI has also described in BCUC IR 1.35.3 (Exhibit B-4, page 103) the types of counterparties it expects to deal with in biogas projects and how they will be different than typical natural gas industry participants. In most cases the biogas upgrading projects will be ancillary activities to the main business of the counterparties such as farming or running a wastewater treatment plant. These parties will want to recover their costs and a reasonable return on any investment they need to make, but they will not want these secondary activities to interfere with their primary business. All these differences between biomethane supply and the CCRA supply delivered by marketers lead TGI to the conclusion that it is not appropriate for the ESM rules to apply to biogas supply contracts.

28. Biomethane Service

28.1 **Notional Gas** - Customers agree and recognize that the location of generation facilities will determine where Biomethane will physically be introduced to the FortisBC Energy System and that Customers receiving Biomethane Service may not receive actual Biomethane at their Premises, but instead be contributing to the cost for FortisBC Energy to deliver an amount of Biomethane proportionate to the Customer's Gas usage into the FortisBC Energy System.

28.2 **Biomethane Physical Delivery** - Customers located in the vicinity of Biomethane generation facilities may receive Biomethane as a component of Gas in such proportion as FortisBC Energy determines in its sole discretion.

28.3 **Reduced Supply** - Customers agree and recognize that the production of Biomethane is subject to biological processes and production levels may fluctuate. Customers registered for Biomethane Service for applicable Rate Schedules 1B, 2B and 3B, agree that in the event that Biomethane production does not provide sufficient gas supply, FortisBC Energy may purchase Carbon Offsets in an amount equivalent to the greenhouse gas reduction that would have been achieved through Biomethane supply, and at a price not to exceed the funding received from Customers registered for Biomethane Service.

28.4 **Price Determination** - Customers registered for Biomethane Service will be billed for Gas pursuant to their applicable Rate Schedule. The cost of Biomethane will be based on the cost of acquiring Biomethane, including, but not limited to commodity, production, infrastructure, equipment and operating costs required to deliver pipeline quality Gas.

28.5 **Biomethane Customers** - Customers registered for Biomethane Service will be charged a Biomethane Energy Recovery Charge based on a calculation that will deem the Customer's Gas usage to be a pre-determined percentage of Biomethane and pre-determined percentage of conventionally sourced Gas. Applicable Rate Schedules will be reviewed and updated quarterly with regard to the price of conventionally sourced Gas and annually with regard to the price of Biomethane with rate changes subject to BCUC approval.

28.6 **Enrolment** - In the event a Customer enters into a Service Agreement with FortisBC Energy for Biomethane Service under Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B, the following terms and conditions will apply:

(a) **Notice** - the Customer will provide notification to FortisBC Energy that he or she wishes to receive Biomethane Service, and FortisBC Energy will provide confirmation to the Customer once the Customer is registered for Biomethane Service.

(b) **Eligibility** - the number of Customers eligible to receive Biomethane Service will be limited and the determination of eligibility will be made by FortisBC Energy in its discretion, acting reasonably.

(c) **Change in Rate** - Customers registered for Biomethane Service will be charged for Gas at the rates set out in Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B. FortisBC Energy will use reasonable efforts to switch Customers to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B in a timely manner. However, Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B rates will only be commenced on the first day of a Month, therefore, Customers registered for Biomethane Service within one (1) week on the last day of a Month may not be switched to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B until five (5) weeks after their registration date.

(d) **Biomethane Service Area** - Biomethane Service is available in all FortisBC Energy Service Areas except the Municipality of Revelstoke.

(e) **Moving** - If a Customer registered for Biomethane Service moves to new Premises within the Biomethane Service Area described above, that Customer may remain registered for Biomethane Service at the new Premises.

(f) **Switching Back to FortisBC Energy Standard Rate Schedule** - Customers may at any time request to terminate Biomethane Service and be returned to a FortisBC Energy conventional Gas Rate Schedule. On receiving notice that a Customer wishes to return to conventional Gas Service, FortisBC Energy will return that Customer to the applicable FortisBC Energy conventional Gas Rate Schedule in accordance with the FortisBC Energy General Terms and Conditions.

(g) **Switching to a Gas Marketer Contract** - Customers may at any time request to terminate Biomethane Service and receive their commodity from a Gas Marketer. On receiving notice that a Customer has entered into an agreement with a Gas Marketer, FortisBC Energy will process this request in accordance with Section 27.

(h) **Program Termination** - FortisBC Energy reserves the right to remove and/or terminate Customers from Biomethane Service at any time.

<u>Appendix E</u>

Natural Gas Vehicles

1. 2008 Long Term Resource Plan Excerpts

2. 2010 Long Term Resource Plan Excerpts

3. CNG-LNG Application Excerpt

4. FEI-FEVI NGV EEC Incentives Review Reply Submissions

7 ALTERNATIVE ENERGY OPPORTUNITIES

The energy planning landscape and trends described in Chapter 2 – growing demand, increasing energy costs and concerns about carbon emissions – have led to renewed interest in a wide range of clean and efficient energy alternatives. Terasen Gas has been developing proposals and opportunities to use the infrastructure and existing resources it already has in place to develop a number of potential alternative energy initiatives. These initiatives are important steps in helping to meet the policies of the B.C. Energy Plan and other provincial and regional energy objectives and in improving the efficiency and optimization of energy infrastructure in B.C.

Although the proposed initiatives discussed in this Chapter do not form part of a traditional resource planning portfolio for Terasen Gas, they do respond to the changing planning environment. The opportunities and initiatives discussed below include both demand and supply side resources. Terasen Gas has chosen to discuss them separately from other resources due to the unique nature and early stages of their development. This discussion provides stakeholders with examples of the types of activities Terasen Gas is undertaking to ensure that natural gas is being used as the right fuel in the right applications to help meet Provincial energy and carbon emission objectives.

7.1 Natural Gas Clean Transportation Opportunities

The 2007 BC Energy Plan ("Energy Plan") sets out a strategy for reducing greenhouse gas emissions and reducing human impacts on the climate. Transportation is a major contributor to climate change and air quality concerns. The use of conventional transportation fuels such as gasoline, diesel, propane and bunker fuel oil accounts for about 39% of B.C.'s GHG emissions[22], the single largest source of greenhouse emissions in the province.

Given its economic and environmental benefits over traditional fuels, natural gas can play a significant role in helping meet the GHG goals set out in the BC Energy Plan 2007 and the air quality goals of the Ministry of Environment. Examples of current technologies and initiatives in other jurisdictions provide an indication of the benefits that can be achieved in B.C. Terasen Gas is working with others in the NGV industry to identify and develop important new NGV initiatives here in B.C. that will help reduce carbon emissions and pollution.

This section describes a number of both near-term and long-term opportunities for the adoption of natural gas vehicles ("NGV") within the transportation industry. Near-term opportunities are defined those where the:

1) technology is proven and commercially available;
2) transition to natural gas technology for the end user is economically and environmentally viable; and
3) technology is supported.

[22] BC Ministry of Environment – based on 2004 data

Terasen Gas has identified near-term opportunities to shift from conventional fuels to NGV technology in a wide range of transportation sector applications such as heavy-duty truck fleets, port materials handling equipment, bus fleets, refuse haulers and port electrification.

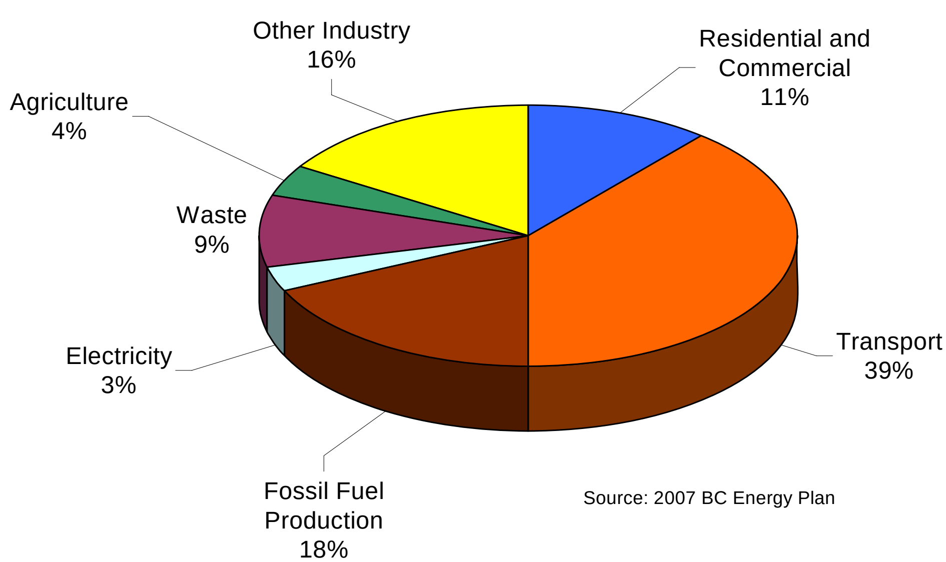
Long-term opportunities are those in which natural gas transportation technology exists, but is not yet commercially proven or available. Terasen Gas believes there are opportunities where natural gas technologies can be adopted in the transport sector for marine passenger vessels and in new light-duty return-to-home fleet or passenger vehicle technology.

The potential natural gas load growth discussed in these examples has not been included in the Terasen Gas demand forecasts due to the uncertainties that remain in capturing this market. As demonstration projects and first adopters in the province show success Terasen Gas expects that markets will begin to grow. As that occurs, Terasen Gas will endeavour to include load growth expectations from this market into its demand forecasts

Air Quality Benefits of Implementing NGV Technology

Figure 7-1 indicates that the single largest source of greenhouse gas in B.C. is the transport sector. Terasen Gas believes that this sector provides the greatest opportunity for greenhouse gas reductions.

Figure 7-1 B.C. Greenhouse Gas Emissions by Sector



Source: 2007 BC Energy Plan

Data from Natural Resources Canada indicates heavy-duty natural gas vehicles emit 15-30 % less GHG emissions than their diesel counterparts. Light-duty vehicles emit almost 30% less

GHG emissions compared to their gasoline equivalents. Natural gas vehicles also emit 50-80% less air quality contaminants such as NOx, SOx and particulate matter[23].

<u>Economic Benefits of Implementing NGV Technology in BC</u>

In terms of fuel costs, natural gas refueling prices at the pump in B.C. are currently up to 50% less than the gasoline equivalent[24]. The recently imposed carbon tax will also affect traditional petroleum fuels to a greater degree than natural gas. This operational cost savings can help to offset fleet conversion costs and in the long run can continue to provide operational efficiencies.

In terms of industry development, the Lower Mainland hosts a cluster of NGV technology expertise and businesses, including Terasen Gas, Westport Innovations, Cummins Westport, Clean Energy, Eco Fuels, MaxQuip, IMW Industries and Powertech Labs. Canadian companies are recognized worldwide as being leading providers of natural gas vehicle technologies and services. Implementing NGV technologies in B.C. will help to develop and support the long-term viability and health of this important industry. Figure 7-2 shows examples of natural gas fuel applications in heavy duty trucks and transit vehicles.

Figure 7-2 Examples of Natural Gas Fuel Technology in Heavy Duty Trucks

Class 8 LNG Truck

CNG Refuse Truck

CNG Articulated Bus

7.1.1 Near-Term Opportunities

7.1.1.1 Ports and Shipping Industry Applications

<u>Heavy Duty Trucks</u>

As a result of the new BC Energy Plan and specific goals in the Pacific Gateway Plan, the Ministry of Transportation ("MOT") and the Climate Change Secretariat are searching intensely for ways to clean up the emissions in British Columbia's Ports. Interest is growing in initiatives that are unfolding in California around truck and ship emissions as opportunities in British Columbia.

---

23 Emission comparisons cited here are available from NRCan GHGenius modeling software available at: http://www.oee.nrcan.gc.ca/transportation/tools/greenhouse-gas-info.cfm?attr=16

24 Based on March 26,2008 gasoline price of $1.20 /litre and CNG pump prices of $0.63 / GLE

San Pedro Bay Ports, operating in the Ports of Los Angeles and Long Beach, have developed an aggressive Clean Air Action Plan ("CAAP") which calls for the replacement of more than 16,000 old Class 8 diesel trucks with several thousand new trucks that operate using LNG fuel technology. The plan includes this and other clean fuel initiatives to meet specifications for reduced particulate matter ("PM") and nitrogen oxide ("NOx") emissions. This movement to cleaner LNG trucks, featuring LNG fuel systems developed and manufactured here in B.C. by Westport Innovations Inc., will result in significantly decreased greenhouse gasses, NOx and particulate emissions. Westport's LNG fuel system is the only alternative fuel technology currently qualified for financial support under the ports' clean truck program.
In the Port of Vancouver, Class 8 trucks are used for transporting containers to and from cargo ships to various hubs throughout the Lower Mainland for distribution throughout North America via rail or long-haul transport. The incremental cost of purchasing a Class 8 heavy-duty truck is approximately $75,000, however; the incremental cost can be offset by fuel savings and the environmental benefits.[25] The near-term business proposal for Class 8 heavy-duty trucks to operate on LNG is for short-haul point-to-point routes where a refueling station is located at one of the points. This is due to the infrastructure investment needed for refueling.

There are currently over 4,000 Class 8 trucks that frequent the Ports of Vancouver, 1,500 of these are regular visitors. Each truck uses approximately 2000 GJ / yr[26]. Terasen Gas believes that with government and industry support a market could be developed starting with a pilot project of 10 trucks, ramping up to 250 -500 trucks over the next 10 years with an estimated consumption is 500,000-1,000,000/GJ per year.

Materials Handling Equipment: Forklifts and Shunt Trucks

Most forklift fleets today use propane as an energy source; however, natural gas is a viable and cleaner alternative. Natural gas as CNG produces fewer emissions, is safer to handle, and is cheaper to operate. In the past five years over 1500 forklifts in the Province of Ontario have converted from propane to natural gas to capture fuel cost savings and air quality benefits[27].

A potential market exists in B.C. for the conversion of propane forklift and shunt trucks (container movers in shipping ports – see Figure 7-3) fleets to CNG. The conversion process includes converting the equipment to use CNG and installing compression and refuelling facilities at the customer premise. Third party vendors are available to provide both the conversion and compression services at either a capital cost to the customer or through a lease back program. By choosing a lease option, the customer will often see immediate savings. The customer may also be eligible for grants to help offset conversion costs. On average, third party vendors report a 15-40% savings on fuel costs for end users that have adopted CNG for their forklift fleets. Current Original Equipment Manufacture ("OEM") products are also available for both equipment types.

[25] U.S. DOE Alternative Fuel Price Report, October 2006.

[26] Information obtained through discussions with industry representatives.

[27] ibid

Figure 7-3 Shunt Truck

Terasen Gas estimates that a market opportunity exists for approximately 300-500 CNG forklifts and shunt trucks. On average each unit uses approximately 200 GJ/year, resulting in a market potential of approximately 60,000-100,000 GJ/year.

Focus on solutions

Natural Gas Fork Lifts

Terasen Gas with its technology partner FuelMaker is converting 100 forklifts from propane fuel to natural gas, for a trans-load shipping operator located in the Lower Mainland. On average a forklift consumes as much natural gas as a house or as much gas as two cars. Not only are forklifts cheaper to operate on natural gas than propane, but they produce well over 50% less smog and 90% less carbon monoxide, yielding great environmental, health, and safety benefits as most forklifts operate indoors.

Cold Ironing

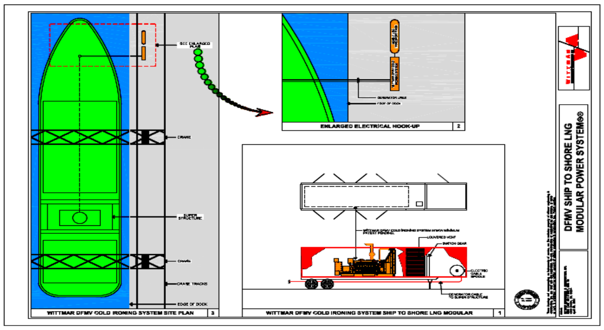
In 2004, the Greater Vancouver Regional District (now Metro Vancouver) identified that by 2006 marine activities would become the single largest producer of smog forming pollutants (NOx+SOx+VOC+PM2.5+NH3) in the Lower Fraser Valley.[28] By 2025, marine activities are anticipated to produce approximately three times more smog than light-duty vehicles.[29]

The primary contributor of air pollutants in British Columbia associated with marine activities occurs from ships while idling in port. When transport ships load and unload while in port - on average a two day process - they continue to burn their own fuel source, often bunker fuel, to run auxiliary engines and power electrical equipment such as navigation, ventilation, refrigeration, and other appliances. Providing shore power for ships (cold-ironing) is a possible solution to the emissions concerns resulting from marine activity. The Port of Oakland has recently completed testing, whereby generators that can run on either LNG or CNG to power the ships while in port. Figure 7-4 provides an illustration of the LNG cold-ironing process and a picture of the proof of concept demonstration at the Port of Oakland.

28 http://www.portvancouver.com/the_port/docs/Air_Quality_Management_in_the_GVRD.pdf

29 Ibid.

Figure 7-4 LNG Cold-Ironing Schematic and In-use Photo



Source: Clean Air Logix

Tests at the Port of Oakland indicate reductions of 94-100% in NOx, SOx, and PM10, and CO and CO2 reductions of 43% and 57% respectively, per 24 hour port call (see Table 7-1). This technology is now included in California regulations for shore power alternatives for ships.

Table 7-1 Pollutant Reductions: Port of Oakland - LNG Cold-Ironing

APL POLLUTION REDUCTION EFFORTS AND RESULTS	Statistics for a 24 Hour Port Call in Oakland				
	2006	2007	LATE 2007		
Fuel Type	2.5% Sulfur Diesel	0.5% Sulfur Diesel	Wittmar DFMV Cold Ironing w/ RML	Reduction	%
NOx	1059 Pounds	1059 Pounds	56 Pounds	94.71	%
CO	79 Pounds	79 Pounds	34 Pounds	56.96	%
PM10	29 Pounds	15 Pounds	0.02 Pounds	99.93	%
SOx	358 Pounds	72 Pounds	0 Pounds	ELIMINATED	
CO2	42,651 Pounds	42,651 Pounds	24,430 Pounds	42.72	%
Fuel Consumption	1,906 Gallons of Diesel	1,906 Gallons of Diesel	2,813 Gallons of RML		

Source: Clean Air Logix, Port of Oakland, Proof of Concept

Terasen Gas continues to closely monitor the developments in California shore power initiatives. Terasen Gas believes that in the next five years there is a potential for three generators at the Port of Vancouver. The estimated consumption would be 300,000 GJ/ year for all three units.

7.1.1.2 Transit Buses

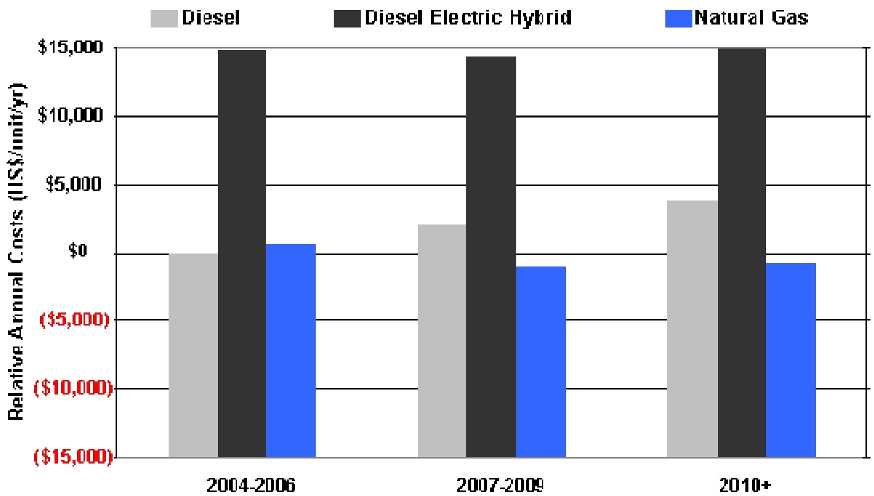
Commercially available OEM engines exist that allow transit buses to operate on CNG. Cummins Westport's ISLG 2007 natural gas engine is already certified to meet 2010 Environmental Protection Agency (EPA) and California Air Resources Board (CARB) emissions standards. This engine is the cleanest heavy-duty commercial technology available.

The incremental cost of purchasing a CNG powered bus over its diesel counterpart is approximately \$50,000[30]. The incremental cost is offset by the environmental benefits and

[30] ibid

lower fuel costs. Figure 7-5 illustrates estimated annual capital and operating cost of CNG buses against diesel and diesel electric hybrid buses.

Figure 7-5 Annual Capital and Operating Costs



The City of Los Angeles has more than 2000 CNG buses, accounting for 94% of their total fleet. In B.C., there are currently 75 CNG buses, (4% of fleet) which operate out of the Port Coquitlam transit hub and are operated by Coast Mountain Bus Company. In January 2008, the Premier of British Columbia in conjunction with the Minister of Transportation announced a $14 billion transportation plan that called for 1500 new clean technology buses. CNG is among the five technologies being considered for this plan.

Given the current policy direction for clean transportation technology, Terasen Gas anticipates there are opportunities over the next seven years, for an additional 150 CNG buses. An additional 150 buses would result in a total of 300,000 GJ/year or 2,000 GJ per bus per year. The total estimated number of transit buses in B.C. greater than 2200.

7.1.1.3 Refuse Trucks

Refuse trucks operating on CNG use the same engine technologies as transit buses. The use characteristics of these vehicles are similar to that of bus fleets. As a result, the economic and environmental benefits of operating a refuse fleet on CNG are similar to those of operating bus fleets on CNG.

Smithtown, Long Island, NY, a suburb of New York City, has recently replaced its entire refuse fleet of 24 trucks to CNG. Smithtown has reported a significant reduction in operating costs, a

20% reduction in greenhouse gas emissions, quieter trucks operating in residential neighbourhoods, and improved breathing conditions for operators.[31]

The most significant challenge with adopting CNG is fleet portability. Many B.C. municipalities outsource their waste hauling contracts through a bid process with contract periods ranging for 3-5 years. If an operator loses a contract in an area after adopting a CNG fleet, it may be costly to move the refueling systems if they have to re-deploy their fleet to another jurisdiction.

With government incentives, and continued municipality commitment to reduce greenhouse gas emissions, this challenge can be overcome. Terasen Gas anticipates that one or two pilot projects can be developed to include approximately 25 CNG refuse trucks using approximately 35,000 GJ/yr or 1,400 GJ per truck per year.

7.1.2 Long-Term Opportunities

7.1.2.1 Light-Duty Fleet & Passenger Vehicles

The successful business model for light-duty fleet and passenger vehicles is similar to the model for heavy-duty trucks. Due to limited refueling infrastructure, vehicles must either operate as a return-to-home fleet with dedicated refueling or operate within an area with retail refueling infrastructure. A significant hurdle in pursuing return to home fleets is the lack of OEM vehicles available in Canada. Terasen Gas believes the majority of CNG fleets over the next 3-5 years will be as a result of converting existing gasoline vehicles to bi-fuel vehicles (run both on natural gas and gasoline).

Vehicles converted in B.C. are predominately converted using a standard EPA approved kit. Depending on the vehicle type, conversions cost approximately \$4,000-\$7,000[32], and customers are eligible for grants of up to \$2500 under Terasen Gas' Rate Schedule 6. The cost of conversion can be offset by the reduced commodity cost of natural gas versus gasoline. Terasen Gas is not aware of any significant fleet conversions to CNG bi-fuel. However, if a lifecycle emission analysis approach similar to that adopted in California is adopted in B.C. there may be significant opportunity to develop a CNG vehicle market for couriers, taxis, delivery vehicles and other light-duty fleets.

Terasen Gas believes that any success in this CNG market segment would have to be driven by CNG OEM engine manufacturers. Terasen Gas is, however, closely following the recent successes of the natural gas powered Honda Civic GX in California and New York State, and is closely monitoring the OEM CNG vehicles manufactured in Europe.

---

31 http://www.nytimes.com/2006/07/30/opinion/nyregionopinions/30LIunderwood.html?_r=1&ref=nyregionopinions&oref=slogin

32 ibid

7.1.2.2 Marine Passenger Vessels

Current technology exists to build ships that can operate on LNG instead of diesel. Given the current energy planning environment and emphasis on greenhouse gas reduction, Terasen Gas believes that in the long term an opportunity may arise to use LNG to operate passenger vessels in British Columbia. Terasen Gas efforts to make LNG available to truck fleets will provide valuable experience as the potential for operating fleet vessels in B.C. is more closely examined.

7.1.3 Standing Tariff for the Sale of LNG

To help open the market for LNG as a fleet fuel, Terasen Gas expects to apply for the approval of a standing tariff for the sale of LNG from its Tilbury LNG peakshaving facility within the coming year. Initially, the tariff would allow for up to 1040 GJ per day (11,700 gallons of LNG) to be sold to customers within the Terasen Gas service territory from the Tilbury facility. As the market for LNG in the fleet transportation sector grows, Terasen Gas will build the necessary infrastructure to support its growth. Infrastructure may include 50,000 to 80,000 gallon storage tanks at Tilbury to facilitate moderate growth and a new LNG facility at either the existing Tilbury site or an alternative location if the market demand justifies the investment.

7.1.4 Natural Gas Vehicle Grants

Under Rate Schedule 6, TGI offers promotional grants towards the cost to purchase factory-built natural gas vehicles, or the cost to convert vehicles to natural gas. The amount of the grant is up to $10/GJ, based on estimated consumption over a one year period, up to a maximum total grant by vehicle type as outlined in Table 7-2.

Table 7-2 Rate Schedule 6 Vehicle Grants

Vehicle Description	GVW (Pounds)	Maximum Grant
Light Duty	< 10,000	$ 2500
Medium Duty	< 17,000	$ 5,000
Heavy Duty	>17,000	$10,000

Terasen Gas may also fund Special Demonstration project grants for innovative applications of natural gas used in vehicles that can be used to demonstrate the technology and promote natural gas as a fuel source for the particular application. The total funds available under the Special Demonstration project grants are $100,000 per year.

7.2 Alternative Supply - Opportunities to Capture Energy from Waste

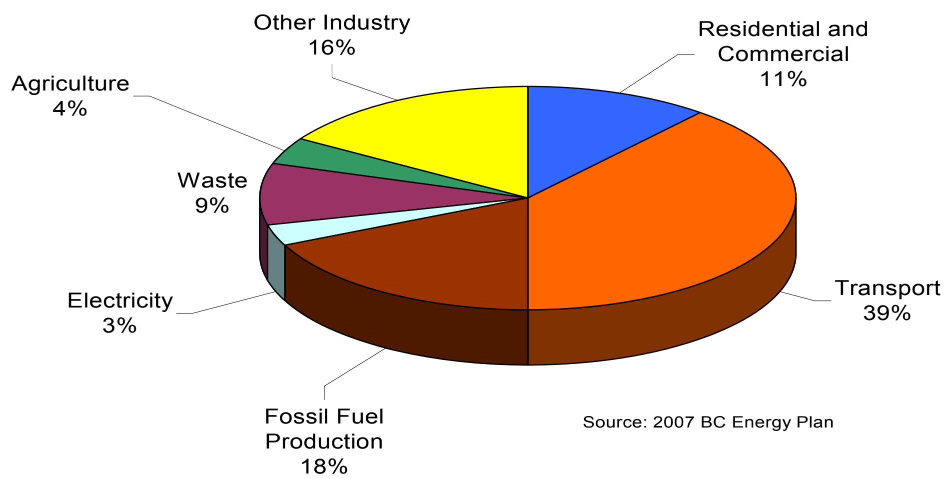
Terasen Gas' initiatives in alternative energy supplies support the 2007 BC Energy Plan objectives of energy conservation and efficiency, innovation to create clean and renewable energy, and developing leadership in clean energy generation. Terasen Gas is examining

3.1.2 NEW NATURAL GAS VEHICLE SOLUTIONS

The Terasen Utilities' customers are seeking integrated, low carbon energy solutions that can help them to manage their energy costs and minimize their carbon footprint. New and complete natural gas vehicle solutions are a vital opportunity for the Utilities to serve these needs and help reach the impressive GHG reduction targets legislated by the Province. This section provides background on NGV technology in B.C., identifies the need and availability of incentive funding for vehicle purchases to spur development NGV solutions, describes the strategy behind new solutions being developed by TGI and presents TGI's intention to bring forward a an application to the Commission for more complete transportation fuel service offerings.

The Utilities see the development of new NGV services, programs and markets as a key part of its low carbon strategy to help meet both the changing needs of our customers and the GHG reduction targets legislated by the Province. The transportation sector is responsible for more energy use and carbon emissions than any other sector (Figure 3-3). As such, it provides B.C.'s biggest opportunity to contribute to a global reduction of carbon emissions and other pollutants over the next 20 years. TGI is developing new NGV solutions that will capture this opportunity for emission reductions, as well as provide an important source of load growth on the Terasen Utilities systems to help optimize system throughput for the benefit of all customers.

Figure 3-3: B.C. Greenhouse Gas Emissions by Sector



Natural gas is a lower carbon alternative to conventional diesel and gasoline and can therefore play a much greater role in this sector than it has historically, improving emissions, reducing reliance on oil and supporting technology development in B.C. Using natural gas instead of conventional fuels reduces GHG and other emissions, such as oxides of nitrogen, sulphur oxides, carbon monoxide and particulate matter. Furthermore, using natural gas for transportation application significantly reduces the customers fuel cost. To capture this benefit, customers must make significant investments in vehicles and equipment that can use natural gas. Given the financial risks, customers are looking to the Terasen Utilities as a trusted partner that can be depended upon to deliver the energy they need for years to come. We believe that the greatest near-term potential to deliver these solutions is in the return-to-base, fleet vehicle market.

As described in Section 2, natural gas is well positioned to compete against conventional fuels which dominate the market for transportation. Low carbon transportation fuel requirements have been legislated, the fuel price advantage for natural gas over conventional diesel and gasoline has improved further, all levels of government are increasing their focus on reducing transportation related emissions and proven technology ready for commercial use is readily available. The Utilities believe that NGVs have a viable and important role to play in the B.C. transportation fuels.

- **Natural Gas Vehicles**

NGVs look like any other vehicle. The difference is NGVs operate on natural gas rather than the fuel we typically pump into our vehicles' tanks. Clean Energy Fuel Corp. offers the following summary:

"NGVs typically use one of two varieties of natural gas: Compressed Natural Gas (CNG) or Liquefied Natural Gas (LNG). CNG is the preferred fueling method for light to medium NGVs, Heavy-duty NGVs with weight and range requirements typically fuel up on LNG, which allows them to store more fuel on board with less tank weight. L/CNG stations can service both types of NGVs by converting LNG into CNG"[72]

In general terms, the benefits of NGVs are:

- Better for the environment, with significantly lower CO2 (carbon dioxide), NOx (nitrogen oxide) and greenhouse gas emissions than the majority of existing vehicles on the road today
- Lower fuel cost - 25 to 50 per cent less than the pump price for gasoline
- Lower maintenance costs - natural gas burns cleaner so engine parts stay cleaner
- A natural resource, produced here in B.C. and elsewhere in Canada

Data from Natural Resources Canada indicates heavy-duty NGVs emit 19-29 % less GHGs than their diesel counterparts. Light-duty vehicles emit almost 30% less GHGs compared to their gasoline equivalents. NGVs also emit 50-80% less air quality contaminants such as NOx, SOx and particulate matter[73].

---

[72] http://www.cleanenergyfuels.com/ngvs_what.html
[73] Emission comparisons cited here are available from NRCan GHGenius modeling software available at: http://www.oee.nrcan.gc.ca/transportation/tools/greenhouse-gas-info.cfm?attr=16

The methodology adopted within the provincial regulation combines measures of the base carbon intensity of the fuel with measures of the efficiency of the engine technology that is used with the fuel. This results in an effective Carbon Intensity in use. CNG has a carbon intensity approximately 38% lower than gasoline and 28% lower than diesel. LNG's carbon intensity is roughly 43% lower than gasoline and 34% lower than diesel[74].

3.1.3 BACKGROUND ON NATURAL GAS VEHICLE SOLUTIONS IN B.C.

Historically, NGV programs in B.C. were focused on the passenger vehicle market through the development of public fueling stations. In 1997 there were 51 public fueling stations in operation in B.C. NGV sales peaked in 1999 reaching 609,000 GJ. Since then, this market has declined due primarily to:

- Lack of OEM vehicle availability - OEM manufacturers exited the market in the 2000/01 time period.
- Unreliable Conversion Technology - Vehicle conversions became more complex with the introduction of electronic engine controls and more sophisticated pollution abatement technologies. After-market conversion technologies had challenges providing reliable vehicle solutions.
- Lack of Support from Fuel Vendors – NGV station providers focused efforts on development of markets in other jurisdictions such as the U.S. market.
- Passenger Vehicle Market Focus – The focus on passenger vehicle markets is more difficult to support as it relies on the development of public fueling infrastructure.
- Modest Price Advantage – In the early part of the decade the pricing advantage of CNG was more modest that it is at present.

Currently, TGI continues to offer NGV Service and modest levels of vehicle incentive grants through Rate Schedule 6. TGI also received approval for the sale of LNG under Rate Schedule 16, Interruptible Liquefied Natural Gas and Dispensing Service[75], effective June 15th, 2009. This rate schedule provides assurance of supply and cost certainty to fleet vehicle and LNG refueling station owner-operators, initiating the development of a new NGV market. LNG sales originate from the Tilbury LNG storage facility in Delta, complementing its existing usage.

---

[74] Low Carbon Fuel Requirements Regulation Intentions Paper for Consultation http://www.empr.gov.bc.ca/EEC/Strategy/BCECE/Documents/LCFRR%20Intentions%20Paper%20Final.pdf
[75] BCUC Order No. G-65-09

> **Terasen's Environmental Leadership in Action: NGV Fleets**
>
> Terasen has incorporated using NGVs for company's fleet vehicles as NGVs, such that fuel savings and the most optimal emissions profile for the company is attained.
>
> Terasen leases or purchases vehicles equipped to operate on natural gas fuel by the original equipment manufacturer if available. Otherwise, Terasen converts units to operate and run on natural gas using aftermarket conversion kits.
>
> 

- **New Incentive Funding**

Vehicle funding to help offset the incremental capital cost of NGVs is a critical driver that motivates customers to adopt natural gas as a transportation fuel. The Terasen Utilities received approval for $2.3 million in 2010 and $4.7 million in 2011 for Innovative Technologies to advance emerging technologies. Since the Innovative Technologies portfolio was formulated, TGI has made progress with some of the technologies, particularly to support implementation of NGV technology. For more information on the Utilities' Innovative Technologies portfolio, see Section 5.

TGI has initiated a pilot incentive program to encourage operators of heavy duty fleets such as garbage trucks and waste haulers to switch to natural gas from higher-carbon diesel. TGI has received expressions of interest from the City of Vancouver, City of Surrey, City of Port Coquitlam, and other third party partner. to use the EEC funding to purchase new natural gas vehicles for garbage collection and transfer operations. Under the provisions of the pilot program, the fleet operators would be reimbursed for the incremental cost of the NGVs over conventional vehicles. TGI expects to assist with funding the adoption of 16 and 32 heavy duty diesel trucks in 2010 and 2011 respectively.

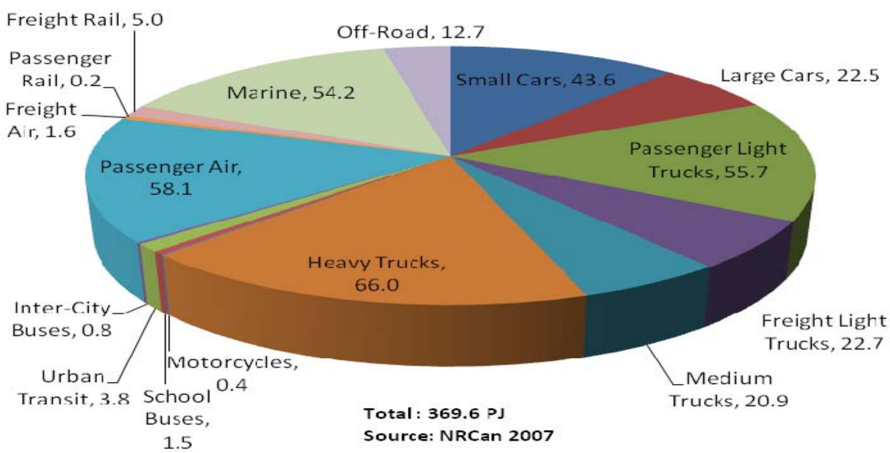
This penetration is based on current cost estimates, allocated funding levels and expression of interest from prospective customers. It should be noted that in the absence of such funding, these operators were not able to commit to NGVs. The higher initial capital cost of NGVs is a significant barrier to adoption in transportation markets but once this is overcome the operator will receive the benefits of lower operating costs and reduced emissions. The success of the initial offering of this program demonstrates there is a strong correlation between incentives and adoption and awareness for emerging technologies. Terasen Utilities believes that the need for such incentives will decline as NGVs gain greater share of the market and the capital cost premium for NGVs declines with volume.

3.1.4 TERASEN UTILITIES NGV STRATEGY

- **Target Market**

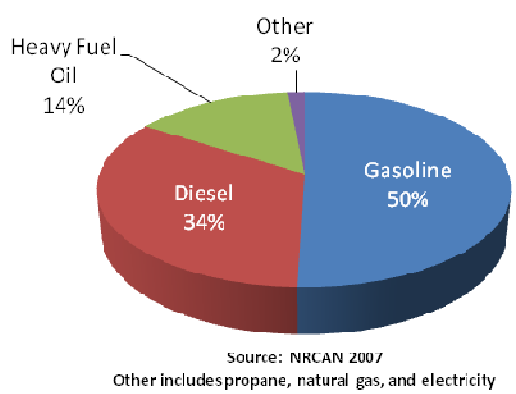
The Terasen Utilities believe the near-term opportunities for natural gas in the transportation sector in B.C. are in the return-to-home applications where commercial fueling technology exists for industrial use vehicles such as light, medium and heavy trucks, waste haulers, as well as bus fleets. Long-term opportunities may exist in marine passenger vessels and in new light-duty passenger vehicle technology. The total transportation sector fuel usage was 370 PJ in 2007 as shown by category in Figure 3-4. Of this total, the target markets that TGI has identified make up 290 PJ. TGI expects natural gas demand from its new NGV solutions to grow to 30 PJ or 6.5% of this total market by 2030. NGV target market segments and demand scenarios are discussed further in Section 4.3.

Figure 3-4: Total B.C. Transportation Market Sector Energy Use by Category (PJ)



The target market can also be broken down by fuel type as shown in Figure 3-5. Gasoline represents 50% of the target market and is consumed primarily in the passenger car and light duty truck segments. Diesel fuel is consumed primarily in the heavy duty and vocational trucking segments. Nearly two-thirds of TGI's NGV growth targets are focused on the high mileage, heavy duty truck segment, where diesel fuel occupies 100% of the market.

Figure 3-5: Terasen Utilities NGV Target Market by Fuel Type



➢ Vehicle Availability

Heavy duty, vocational fleets (ie. garbage trucks), and transit buses can be serviced and supported through an existing dealer network. OEM product offerings exist in the heavy duty segment from manufacturers such as Kenworth and Peterbilt, in the transit segment from New

Flyer, and in the vocational truck market from Crane Carrier, Autocar, Freightliner, and Mack. The light duty and medium truck segments are more challenging. At present the approach being utilized within the TGI fleet is to purchase OEM equipment that is factory prepared and certified to be "NGV Ready" for subsequent conversion by qualified aftermarket conversion suppliers. This approach is presently offered by Ford on a variety of truck and van models. General Motors has also announced a return to providing OEM Natural Gas ready vehicles.[76] Additionally, the marine segment has OEM manufacturer availability from Rolls Royce and Wartsilla.

- **Focus on Commercial and Fleet Vehicles**

TGI aims to concentrate on commercial and fleet vehicles that operate out of a single location, or between a limited number of points. A constrained service area makes the refueling investment more manageable. The medium and heavy duty truck segments, as well as transit buses consume high amounts of fuel. Specific consumption level expectations are described in Section 4.3.

The business strategy should focus on fleet vehicles that can be economically served by a minimal number of fueling stations. This implies a focus on "return home" fleet vehicles and vehicles that operate between a limited number of destinations (e.g. ferries or long haul trucks that travel from point to point.

- **Fueling – A Complete Offering**

A successful development strategy will need to provide a complete offering to the fleet customer. TGI's strategy will require extension of the service offering to provide fueling station assets and services. For CNG applications, a compression, storage and dispensing service needs to be added. For LNG applications, a local storage and dispensing service needs to be added. TGI has been exploring this market place for some time now and to date, no other businesses are stepping forward to fulfil this role in B.C..

The task of establishing fueling infrastructure is not trivial and requires experience and expertise with respect to compressed gas facilities and/or cryogenic fuels facilities. The provision of these services is consistent with TGI's role as a trusted supplier of energy products and services and should be part of our service offering.

As discussed above, provision of fueling services is a key element of TGI's new NGV strategy. We propose the addition of services for both CNG and LNG fueling stations.

- CNG - Compression, high pressure storage, dispensing and metering assets
- LNG - Cryogenic storage, dispensing and metering

[76] Oilweek magazine June 2010: http://www.oilweek.com/articles.asp?ID=732

The assets provided for each station are different but the service and proposed rate model are the same.

By providing commercial fleet customers with an offering that is readily comparable to their existing fuel products (ie. gasoline, diesel), the benefits of NGVs may be easier for customers to understand. For commercial fleet customers, this means providing a single bill from a single vendor which includes all service up to the point where fuel is delivered into the tank.

TGI is presently exploring project proposals with the City of Port Coquitlam and another third party interest. These projects involve heavy duty vocational trucks that run on CNG. The aforementioned parties communicated to TGI that trucks would use approximately 1100 GJ/unit/year over an average total distance of 40,000 kilometers per vehicle per year.

In 2009, TGI, Westport Innovations, and IMW Industries combined with Wastech Services Ltd. for a pilot project where solid waste was transported using heavy duty LNG garbage trucks, from Greater Vancouver to the Cache Creek landfill[77]. The results of the study concluded that the NGV trucks would consume up to 9,500 GJ/unit/year over an average total distance of 389,000 kilometers per vehicle per year. TGI is also exploring a potential project with the City of Vancouver's fleet of waste transfer vehicles. These vehicles consume approximately 1,500 GJ per year operating approximately 80,000 kms per year. It is expected that fleets with high mileage are more likely to convert to LNG operation as the operating cost savings will be greater for these fleets. Given the range of potential fuel consumption and the propensity for LNG customers to be high mileage applications, TGI believes that 2,500 GJ/truck/year is a reasonable estimate for average heavy duty vehicle fuel consumption.

3.1.5 CONCLUSIONS AND NEXT STEPS FOR NEW NGV SOLUTIONS

TGI's new NGV initiatives can provide substantial GHG and other emission reductions from the largest emitting sector in B.C. The transportation markets we are targeting (light, medium and heavy duty trucks, transit, marine fleets and potentially rail) emit almost 50% of transportation related emissions in B.C. These initiatives can help our customers manage their costs and carbon footprints, and help meet the Province's emission reduction targets. Our low carbon fuel strategy targets return-to-base fleet vehicles for CNG solutions where fueling infrastructure economics make sense and vehicle ranges can match fuel capacity. Transport industry fleets with large engines present LNG solution opportunities where larger fuel capacities are needed for heavy duty or longer haul operations. Marine and rail fleets offer future LNG fueling opportunities.

The Terasen Utilities have a role to play in removing the barriers that will enable the development of an NGV industry in B.C., which will help new customers reduce their GHG emissions in a cost effective manner, while providing benefits to existing customers by

[77] http://www.wastech.ca/uploads/media%20material/090507_Wastech_LNG_mediapkg.pdf

improving the utilization of the existing natural gas infrastructure. The Utilities expect to grow demand in its NGV target market to 30 PJ annually by 2030. NGV solutions must be complete solutions, however, and provide the customer with service that allows them to directly fuel their vehicles and equipment without the need for them to supplement a portion of the service, or risk the unwillingness to participate in this important opportunity.

TGI intends to bring forward an application to the Commission in the summer of 2010 for approval of more complete transportation fuel service offerings. That application will include the requirement for and appropriate treatment of CNG and LNG fueling infrastructure being sought from the Utilities by existing and potential future customers. Extension of a more complete NGV service to the TGVI and TGW service territories is contemplated at a later date pending future unbundling of gas delivery rates for these utilities.

More Opportunities for Compressed Natural Gas:
Napa Valley Wine Train Example

The Napa Valley Wine Train started a program for the experimental conversion of a Napa Valley Wine Train Alco locomotive to 60% natural gas and 40% diesel fuel mixture. In 1999 the conversion became permanent. A total conversion of locomotive 73 was completed and it was put into service using 100% Compressed Natural Gas on in 2008.

Source: http://winetrain.com/about/our-train

3.1.6 CARBON NEUTRAL BIOMETHANE OFFERING

Biogas is a readily available supply of renewable gas from landfills, sewage treatment plants, food waste, and agricultural operations. Established technology exists that can be used to upgrade biogas to biomethane, which has characteristics that make biomethane a reliable and safe substitute for natural gas. Moreover, biomethane is a renewable fuel. The production and consumption of biomethane is considered carbon neutral. The use of this carbon neutral fuel in place of a carbon positive fuel such as natural gas results in a net reduction of GHG emissions as well as other environmental and economic benefits for potential biogas producers throughout the province. This offering to customers promotes government's energy policy objectives

3 PROPOSED SERVICE OFFERING BENEFICIAL TO CUSTOMERS AND SUPPORTS ENERGY OBJECTIVES

As discussed in Section 2 of this Application, offering LNG and CNG Services requires some investment in fueling infrastructure, the cost of which is to be recovered through contractual rates charged to the NGV customer. TGI's investment in infrastructure backed by a long-term "take-or-pay" contract generates immediate and direct benefits not only for the NGV customer but also for existing natural gas customers and British Columbians generally. Over the longer term, TGI's involvement as a market participant promotes the efficient development of natural gas as a transportation fuel,and will help stimulate the market, which does not appear to be gaining any traction without TGI's involvement, while continuing to accommodate other companies that may wish to offer the same service.

This section discusses three key reasons why it is in the public interest for TGI to invest in the necessary fueling infrastructure where the investment is backed by a multi-year "take or pay" contract. In particular:

1. Section 3.1 discusses how the addition of natural gas transportation load associated with a new NGV contract provides an immediate benefit to existing and new gas customers through lower delivery rates all else equal. Over time, the addition of NGV load has the potential to be a significant benefit to existing and future natural gas customers, which are being faced with declining load from traditional end uses.
2. Section 3.2 discusses how potential NGV customers benefit from accessing natural gas in a usable form from TGI in addition to other potential NGV providers. These benefits include:
    a) NGV customers can enjoy a fuel price differential compared to diesel or gasoline;
    b) Natural gas experiences more price stability; and
    c) Customers can reduce their carbon footprint.
3. Section 3.3 outlines how TGI's investment in fueling facilities that will enable a fleet to be converted to NGV supports government policy and, specifically, British Columbia's energy objectives. Federal, provincial, regional, and municipal governments are increasingly focused on addressing climate change and pollution. Governments at all levels are adopting policies in favour of lower carbon energy forms as a key part of the solution to help achieve these goals.

The proposed rate structures, which contemplate investment in projects backed by "take-or-pay" service agreements, generate immediate benefits for existing natural gas customers and stand on their own regardless of how successful TGI is in developing the NGV market in the long-term.

3.1 Existing Customers Benefit From Increased Throughput

NGVs represent a currently untapped customer segment that can add high load-factor throughput to make better use of the existing TGI infrastructure. Terasen Gas customers will achieve lower delivery rate benefits, all else being equal, as a result of the increased throughput on the system that is attributable to the NGV fueling service. As with any instance where cost effective load is added, each “take-or-pay” service agreement incorporates rates that recover the cost of providing service and thus confers a direct benefit on existing and future natural gas customers. While individual agreements will not, in isolation, result in material changes in delivery rates, TGI believes that there is significant market potential for NGVs in British Columbia (see Appendix A) and thus significant possible future benefits for existing and future natural gas customers.

In this Section, TGI:

- Explains how the addition of cost-effective load reduces delivery rates, all else being equal;
- Puts the WM Agreement into perspective in terms of the amount of load it is adding to the system for the benefit of all customers; and
- Provides some information about the potential benefit in terms of reduced delivery rates that could be achieved over time by adding NGV load.

3.1.1 ADDITION OF COST EFFECTIVE LOAD REDUCES DELIVERY RATES

As with any instance where cost-effective load is added, each “take-or-pay” service agreement incorporating rates that recover the cost of providing service confers a direct benefit on existing and future customers. The Company has been experiencing a trend towards lower use per customer in recent years, which results in upward pressure on delivery rates, all other things being equal. This occurs by virtue of the fact that the revenue requirement is shared over fewer GJs of throughput. NGV load will serve to mitigate some of the delivery rate pressure that existing customers may face in years to come as natural gas demand for heating declines. Moreover, NGV load tends to be more year-round in nature than low load factor space heating, which is the dominant contributor to demand in the residential and commercial customer segments. TGI has developed the cost of service model and rate structures to ensure that NGV load is cost-effective and thus beneficial to existing and future customers.

3.1.2 WM AGREEMENT IN PERSPECTIVE

Although individual agreements with an NGV customer will not, in isolation, result in material changes in delivery rates, it is useful to put these agreements in the context of how the added load compares in terms of residential customer additions. As an illustration, the WM Agreement described in detail in Section 4 is expected to add approximately 21,000 GJ of load per year, with Waste Management paying for the incremental cost of service.

The addition of 21,000 GJ per year is the equivalent of TGI adding 221 average Lower Mainland residential customers (assuming residential use rates of 95 GJ / yr). One natural gas garbage truck, for example, is akin to adding 10 of these average residential customers. In 2009, the Terasen Utilities will add just over 8,000 residential customers representing approximately 760,000 GJs[12]. The annual load under the WM Agreement alone will represent 3% of the residential load added in 2009. Put another way, TGI would need only 36 NGV stations with the same "take-or-pay" demand as the WM Agreement to add, on an annual basis, the equivalent residential load added in all of 2009. These figures illustrate why it is important for TGI to provide a service offering for NGVs that will help to add load.

3.1.3 POTENTIAL DELIVERY RATE BENEFIT OVER TIME

TGI has performed an analysis of the long-term potential NGV market in B.C. and the impact various demand scenarios could have on rates (all other things being equal). The impact under each scenario will be further discussed.

TGI's demand forecasts for NGV were addressed in the 2010 LTRP, and the Company is including them in this context only to illustrate how added NGV load can translate into benefits for existing and future customers. The Company believes that since the proposed rate structures contemplate investments backed by "take-or-pay" commitments from customers that will cover the incremental cost of service, it is unnecessary for the purposes of this Application to assess the reliability of the long-term demand forecasts.

3.1.3.1 Demand Forecast Scenarios

As detailed in Appendix A-1 Demand Forecast as well as the Terasen Utilities 2010 Long Term Resource Plan[13], Terasen Gas forecasts that by 2030 there is market potential for:[14]

- 30 PJ of total energy use under the Reference Case which targets Buses and Medium and Heavy Duty Trucks;
- 13 PJ of total energy use under the Low Growth scenario targeting only Heavy Duty Trucks; and
- 36 PJ of total energy use under the Reference Case Plus Passenger Growth scenario.

30 PJ of natural gas demand for transportation represents about 6.5% of the Company's target transportation market (458 PJ) in 2030.[15] For illustration purposes, TGI will use those demand forecasts for calculating the potential favourable impact on delivery rates associated with NGV

[12] Assuming a Lower Mainland residential use rate of 95 GJs / year
[13] In addition to the information filed previously in the Terasen Utilities 2010 Long Term Resource Plan, TGI has expanded upon the previously-filed data to include a NGV station and station capital forecast.
[14] Scenario forecasts are expressed as rounded totals. Please see Appendix A-1 for actual data.
[15] Estimation based on the assumption that the current target market size grows at approximately 2% per year, equal to rate of GDP growth, based on current 5 year B.C. Ministry of Finance GDP forecast. See Appendix A-1 for the detailed analysis.

load. It should be noted, however, that the portion of the NGV market that is targeted by the proposed CNG and LNG Services is only a subset of this demand. NGV offerings would ultimately have to extend beyond the proposed offering to capture the full extent of the demand forecast.

3.1.3.2 Methodology for Calculating the Favourable Impact on Delivery Rates

Terasen Gas has used the projected increases in natural gas system load for each of the three scenarios (Reference Case, Low Growth, and Reference Case plus Passenger) as identified in Appendix A to calculate the impact to revenue requirements and the corresponding impact to Terasen Gas delivery rates under each scenario.[16] To determine the incremental revenue requirement benefit, Terasen Gas multiplied the volumes in each of the three scenarios by the approved 2011 volumetric delivery rates for three rate schedules. Each of the target market categories described in Appendix A are listed below in Table 3-1 and were assigned to an existing TGI Rate Schedule.[17]

The revenue requirement benefit represents the increase in delivery margin from the incremental volumes associated with the NGV fueling service and is offset by the cost of service of the forecast EEC innovative technologies funding attributable to NGV fueling service. As the incremental cost of service for adding an NGV customer (e.g. dispensing infrastructure) is paid by the NGV customer, this is not a factor in the calculations.

The table below demonstrates the annual benefit that existing gas customers experience in each of the three scenarios.

Table 3-1: All Customers Benefit from Increased Throughput

Impact to Existing Natural Gas Customers: NGV Refuelling Service	2012	2015	2020	2025	2030
Forecast Revenue Requirement Reduction (Increase), $000's					
Reference Case	384	2,285	12,501	39,829	82,451
Low Growth	308	730	5,059	15,865	33,377
Plus Passenger	421	2,650	17,973	50,773	104,339
Approximate Annual Delivery Rate (Decrease) Increase, %					
Reference Case	-0.07%	-0.42%	-2.31%	-7.36%	-15.24%
Low Growth	-0.06%	-0.14%	-0.94%	-2.93%	-6.17%
Plus Passenger	-0.08%	-0.49%	-3.32%	-9.38%	-19.29%

[16] Please see Appendix A-1 for the detailed analysis. The analysis excludes current transportation load in 2010 of 211,939 GJ from each scenario.

[17] Please see Appendix A-1 for the detailed analysis. In general, Transportation Rate Schedules have the following definitions:
Rate Schedule 6 (NGV Vehicle Service) – CNG service, no minimum GJ
Rate Schedule 16 (LNG Sales and Dispensing Service) – sale of LNG, maximum of 1,040 GJ/day
Rate Schedule 25 (General Firm Transportation Service) – CNG service, greater than or equal to 6,000 GJ per month. While other Transportation Rate Schedules exist (22, 23, 26, and 27) this analysis only considers the three for simplicity.

The results are consistent in all three demand forecast scenarios: increased throughput from the NGV fueling service results in a favorable reduction in delivery rates for Terasen Gas existing natural gas customers, all other things being equal. Under the Reference Case, existing natural gas customers benefit with a significant 15.2% reduction, or $82.5 million, in delivery rates in 2030. In today's dollars, this is an approximate revenue requirement reduction of $22.0 million.

Terasen Gas believes that the Reference Case scenario is the most likely of the three NGV demand scenarios developed, as it is based on the current positive external opportunity for increased adoption of NGV solutions as described above. This scenario is based on the best possible information available today on expected vehicle growth in the defined target segments, continued incentive funding expectations, favourable natural gas prices and availability of fueling infrastructure. The assumptions underlying this scenario are:

1. Adoption of NGV solutions over the long-term across all the identified target market segments except passenger cars;[18]
2. Incentive funding[19] will continue to be a driver to reduce the initial incremental capital cost across the entire target market segments excluding passenger cars;
3. In the later years, there is increased adoption and uptake of NGVs from the success of the initial pilot projects;
4. Public policy will continue to support the use of natural gas as a transportation fuel to meet climate action legislative targets;
5. Natural gas commodity prices will continue to maintain or increase its advantage against conventional fuel types as more shale gas comes online;
6. Economies of scale from OEM vehicle manufacturers and station manufacturers will help push the initial capital costs for natural gas fuelled equipment down over the longer term;
7. Availability of targeted fueling infrastructure supports the expected demand and uptake;
8. OEM vehicles and improvements in conversion technology are available across light duty and medium duty vehicles.

The Reference Case forecasts a demand of 34,540 NGVs by the end of 2030, which would require an estimated 405 stations to provide fueling service. Of those stations, 143 would provide LNG service and the remaining 262 CNG service.[20] The composition of NGVs is shown Appendix A, and a summary of the station infrastructure is shown in Table 3-2.

[18] Passenger vehicles are not pursued as a near-term target by Terasen Gas due to their low fuel consumption and limited fueling infrastructure, and thus a limited economic incentive to switch from gasoline to natural gas.
[19] From Terasen Gas EEC Innovative Technologies and potential government sources.
[20] Please see Appendix A-1, Section 2.2.1 for the fuel type consumption assumptions for each vehicle category

Table 3-2: Reference Case demand for 405 total fueling stations by 2030

Category	Total Number of New Stations - Reference Case				
	2011	**2015**	**2020**	**2025**	**2030**
Light Duty Trucks (CNG)	-	5	51	91	158
Medium Duty Trucks (CNG)	-	1	8	20	25
Heavy Vocational Trucks (CNG)	1	4	17	41	61
Heavy Duty Trucks (LNG)	1	7	30	68	118
Buses (CNG)	1	4	12	15	20
Marine Vessels (LNG)	-	1	4	13	23
Cumulative Total:	3	23	122	248	405

Note: Does not include existing public or private stations in B.C.

The delivery rate benefit associated with NGV fueling service will serve to mitigate some of the delivery rate pressure that existing customers may face in years to come as a result of natural gas demand declines. Furthermore, increasing NGV load offers additional benefits to the natural gas system as NGV load tends to be more year-round in nature than low load factor space heating which is the dominant contributor to demand in the residential and commercial customer segments. TGI's near-term target market that could be served by an anchor tenant model is a subset of this demand forecast, therefore TGI would seek Commission approval to pursue other business models to serve NGV demand should the demand for other models materialize.

3.1.4 CONCLUSION

The changing nature of market conditions for NGV solutions in B.C. has opened up an important new target customer segment for Terasen Gas. However, significant NGV adoption is unlikely to occur in the province unless adequate station infrastructure is provided. Terasen Gas can serve a sub-set of NGV demand on a low-risk basis whereby the NGV customer pays on a "take-or-pay" basis for the incremental cost of service associated with installing a fueling station. The proposed WM Agreement is an illustration of this approach. Any future initiatives to expand the Company's basis for serving NGVs beyond the proposed "take-or-pay" contractual model would be submitted to the Commission for consideration. Ultimately, all TGI customers will benefit from lower delivery rates as a result of the increased throughput on the system that is attributable to the CNG and LNG Services proposed in this Application.

3.2 Benefit to NGV Customers

In the previous Section, TGI explained the benefits of additional NGV load for all existing and future customers through reduced delivery rates, all else equal. The proposed offerings also directly benefit potential NGV customers. Potential customers in the transportation industry that are able to adopt NGV technology can achieve some important benefits, including:

- Operating cost savings;
- Reduced fuel cost volatility as compared to diesel and gasoline; and
- Reduced GHG emissions.

The unavailability of fueling infrastructure and a secure supply of CNG or LNG currently represents an obstacle to customers' adoption of NGV technology. TGI, by providing access to fueling infrastructure and a secure supply of CNG or LNG pursuant to the proposed rate offerings, removes that obstacle.

In this Section, TGI will address the three key benefits, identified above, that potential customers such as Waste Management will see as a result of TGI's CNG and LNG Service offering.

3.2.1 OPERATING COST SAVINGS

Terasen Gas has performed an analysis of the up front cost of NGVs (either OEM NGVs or after market conversions) and the savings in operating costs associated with NGVs over time. The results of that analysis demonstrate that the adoption of NGVs can be beneficial to the customer. TGI discusses the elements of its analysis below.

3.2.1.1 Cost of NGVs to Customer

At present, OEM NGVs command a price premium over their conventional fuelled equivalents. The below Table 3-4 shows this price differential of each target market segment. In general, this premium is recovered over time through the fuel savings of natural gas. Depending on fuel consumption, a typical payback would be between 4-6 years for heavy-duty trucks. The table also shows today's approximate cost of engine conversion (using after market conversion kits) for use in Light and Medium Duty vehicles. This cost has increased significantly from the $2,000 - $3,000 per installation in the late 1990s.[21]

[21] Based on conversations with conversion specialist Excel Fuels Installations. Prices do not include incentive funding, grants, or subsidies.

Table 3-4: NGVs Price Premium over Conventional Vehicles

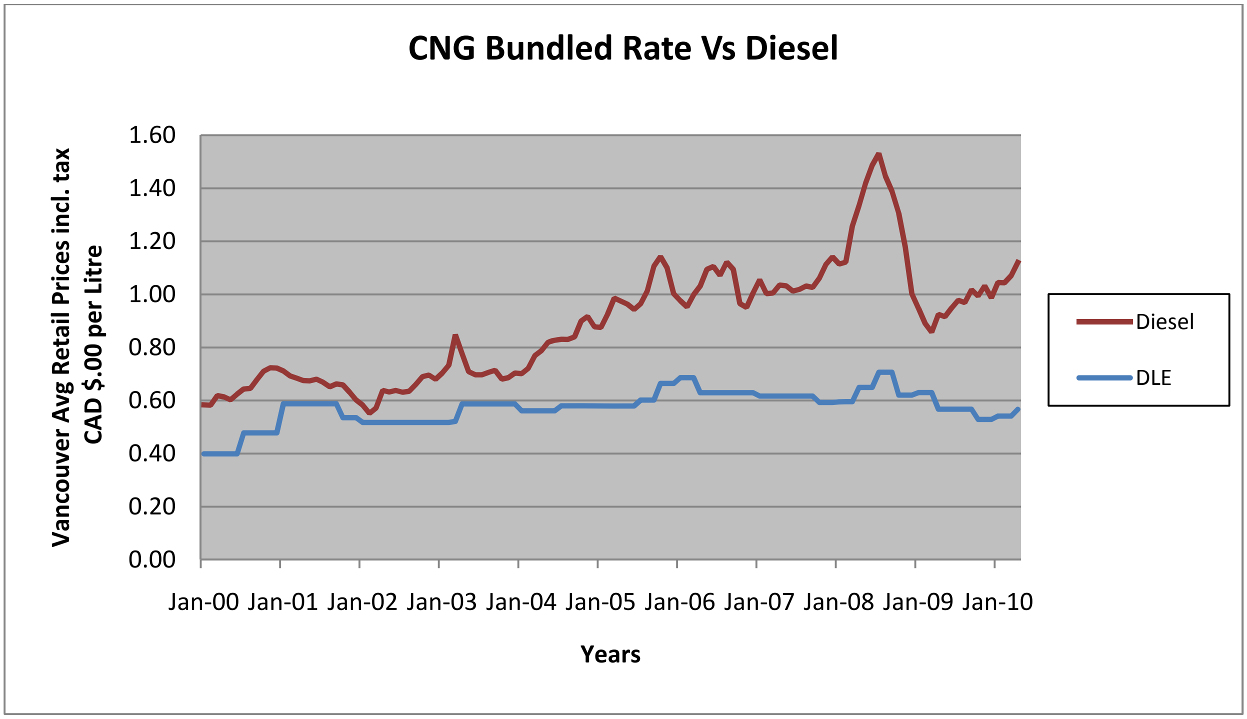
	Conventional Vehicle			Natural Gas Vehicle			NGV
Vehicle Category	**Product**	**Fuel Type**	**MSRP**	**Product**	**Fuel Type**	**MSRP**	**Price Premium**
Passenger Car	Honda Civic	gasoline	$20,820	Honda Civic GX	CNG	$29,600	$8,780
Light Duty Vehicle	engine conversion	diesel	-	engine conversion	CNG	$5,000 to $7,000	$5,000 to $7,000
Medium Duty Vehicle	engine conversion	diesel	-	engine conversion	CNG	$8,000 to $10,000	$8,000 to $10,000
Heavy Duty Vehicle	vocational truck	diesel	$250,000	vocational truck ISL - G	CNG	$305,000	$55,000
Heavy Duty Vehicle	tri-drive tractor	diesel	$145,000	tri-drive tractor GX	LNG	$223,000	$78,000
Transit Bus	New Flyer	diesel	$435,000	New Flyer CNG	CNG	$504,000	$69,000

3.2.1.2 Pricing Comparisons Between Fuels

Natural gas has historically enjoyed a pricing advantage over other motor vehicle fuels (diesel and gasoline). The operating cost savings attributable to the favourable price differential between natural gas and other motor vehicle fuels create the opportunity for overall savings for customers, despite the relatively higher cost of OEM NGVs and after market conversions. As an illustration, TGI explains in this section the magnitude of the differential between CNG and diesel, and CNG and gasoline, in previous years, and how that would have translated into savings for customers. The market indications show that natural gas is likely to retain its price advantage over incumbent fuels for the foreseeable future, meaning that this opportunity for customers to benefit will continue to exist provided the appropriate NGV fueling infrastructure is in place to serve these customers.

Figure 3-1 below illustrates the advantage of natural gas over diesel over the past 10 years. In the period between 2001 and 2003 the gap narrowed to the point where it became difficult to pay back the incremental cost of the NGVs. Since 2005, however, the gap has widened.

Figure 3-1: Proposed Offering Would Have Historically Beaten Diesel on Price



Notes:

- Average pump prices for low sulphur diesel in Vancouver include all applicable taxes. Terasen Gas CNG prices include $5 per GJ compression charge and applicable Rate Riders.
- CNG pricing is based on Rate Schedule 6 historical pricing with an additional $5/GJ to cover the costs associated with compression and dispensing the fuel.
- CNG pricing is converted to Diesel Litre Equivalent basis for ease of comparison to diesel. The conversion is based on energy content values published in the NRCan GHGenius model[22]. (Diesel at 38.653 MJ/litre – yields conversion factor of 25.9)

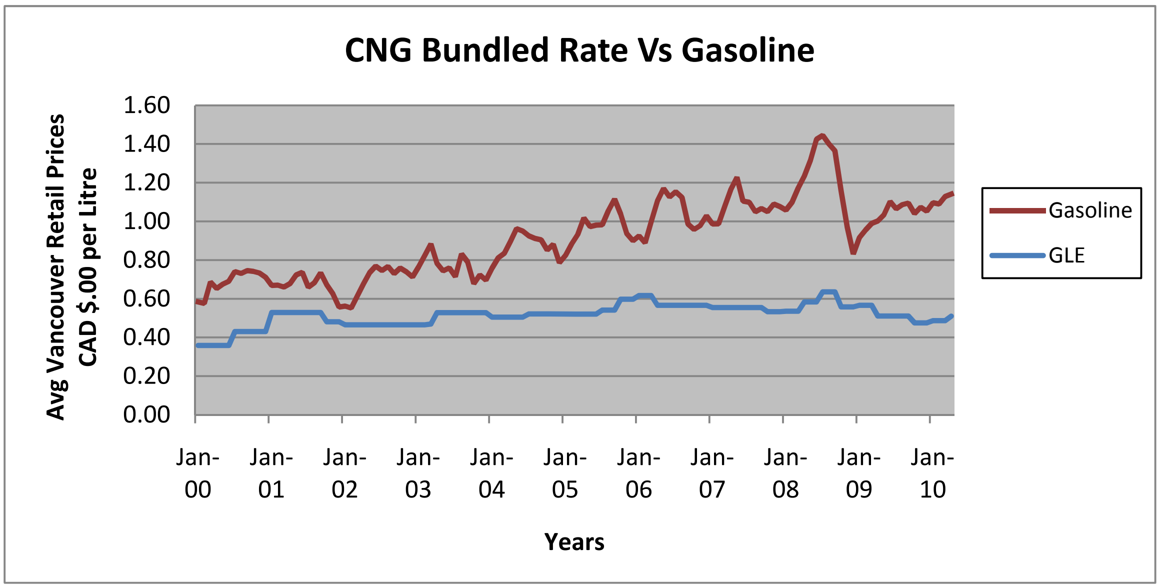
The graph shown above in Figure 3-1 demonstrates that a CNG offering as proposed in this Application, if priced at approximately $5/GJ, would have consistently been less expensive than diesel for the entire preceding decade. The $5/GJ is an approximation based on a high-level analysis of the cost of service of many large NGV projects.[23] Such an offering would currently have a price advantage over diesel of approximately $0.40/litre, or 40% as of the date of the filing of this Application. These fuel savings can offset the upfront price premium for NGVs (see Table 3-4) over time. The typical payback for a heavy duty fleet operator switching from diesel

22 http://www.ghgenius.ca/downloads.php
23 Terasen Gas has selected $5/GJ based on historic diesel fuel consumption and fueling station capital cost estimates provided by large fleet operators in BC. The proposed rate structure is described in Section 2 of this Application.

to CNG is approximately four to six years. The combined price advantage and stability is something that Terasen Gas believes would be very attractive to fleet managers.

TGI's near-term focus is commercial, return-to-base, heavy duty fleet vehicles which operate on diesel. Since there are a number of return-to-base fleets which also run light duty vehicles on gasoline, a comparison of CNG versus gasoline is also included. Figure 3-2 below illustrates the advantage of natural gas over gasoline over the past 10 years. In the period between 2001 and 2003 the gap narrowed to the point where it became difficult to pay back the incremental cost of the NGVs. Since 2005, however the gap has widened.

Figure 3-2: Proposed Offering Would Have Historically Beaten Gasoline on Price



Notes:

- Average pump prices for regular unleaded gasoline in Vancouver include all applicable taxes. Terasen Gas CNG prices include $5 per GJ compression charge and applicable Rate Riders.
- CNG pricing is based on Rate Schedule 6 historical pricing with an additional $5/GJ to cover the costs associated with compression and dispensing the fuel.
- CNG pricing is converted to Gasoline Litre Equivalent basis for ease of comparison to diesel. The conversion is based on energy content values published in the NRCan GHGenius model[24]. (Gasoline at 34.686 MJ/litre – yields conversion factor of 28.8)

The graph shown above in Figure 3-2 demonstrates that a CNG Service offering as proposed in this Application, if priced at approximately $5/GJ, would have consistently been less expensive than gasoline for the entire preceding decade. Such an offering would currently have a price advantage over gasoline of approximately $0.60/litre, or 55% as of the date of the filing of this Application, even more significant than the price advantage of natural gas over diesel. The

[24] ibid

typical payback period for light duty NGVs is generally longer than heavy duty NGVs. This is one reason why light duty vehicles are not part of TGI's near-term target market.[25] The combined price advantage and stability is something that Terasen Gas believes would be very attractive to fleet managers.

3.2.1.3 Natural Gas Likely to Maintain Price Advantage Over Diesel Oil

The market indications, as reflected in the forward market prices, show that natural gas is likely to retain its price advantage over incumbent fuels for the foreseeable future, meaning that the payback period remains favourable for the adoption of NGV in place of diesel.

Historically natural gas prices have been heavily influenced by oil prices due to the short term substitutability of crude oil products, such as fuel oil, with natural gas for industrial and commercial processes and electricity generation. As illustrated in Figure 3-3[26], price fluctuations in crude oil prices can have major impacts on natural gas prices regardless of the fundamental supply and demand factors that underpin gas prices. This was observed during mid-2008 when crude oil rallied to over $145 US per barrel by July, pulling up natural gas prices to almost $14 US/MMBtu. Prior to this time, natural gas prices were typically bounded by fuel oil as the ceiling and heating oil as the floor, and breakouts from this range were seldom. During the hurricane season of 2005, hurricanes Katrina and Rita disrupted natural gas production in the Gulf of Mexico to such an extent that natural gas prices temporarily rose above heating oil prices.

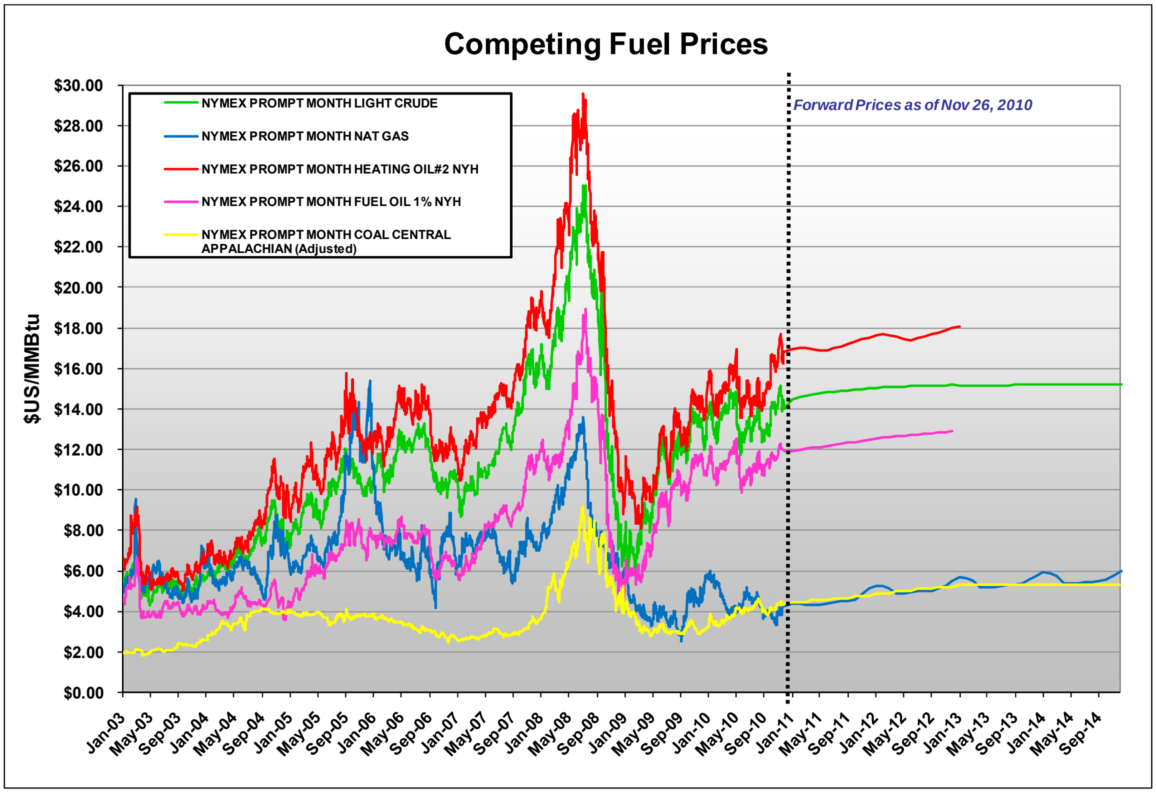
Since the collapse of oil prices after mid 2008, natural gas prices have disconnected from oil and related oil product prices. Natural gas prices have traded below those of fuel oil and the ratio of natural gas to oil prices has widened from the historical average of about ten to one to about twenty to one. The reason for this disconnection lies with the supply and demand balances for natural gas and crude oil. Natural gas is based on supply and demand factors in North America. Currently, natural gas prices are the lowest in many years due to weakened industrial demand due to the recent recession and strong production from unconventional (especially shale gas) supplies. Crude oil, on the other hand, is a globally traded commodity, and prices are dependent on international supply and demand factors. Currently, the crude oil supply and demand balance is tight, meaning that demand is strong relative to available supply. Strong economic growth from China and India has increased the demand for oil in recent years. Furthermore, geopolitical events affecting global crude oil supply have created a risk premium associated with crude oil, somewhat inflated prices. Examples of geopolitical risks include disruptions by Nigerian militants on pipeline infrastructure, tensions between Iran and the U.S. over Iran's nuclear program and conflicts between North and South Korea. Furthermore, the Organization of Petroleum Exporting Countries' ("OPEC") influence on supply and oil prices is also significant. OPEC has indicated that its preference is for crude oil prices to remain near

[25] Please see Appendix A-1 for additional details
[26] As presented on page 19 of the Terasen Utilities 2010 Long Term Resource Plan

$80 US per barrel. Any significant deviations in crude oil prices from this level are likely to be met with supply adjustments by OPEC.

Consequently, with depressed natural gas prices, the price of coal is becoming increasingly relevant by acting as the floor for natural gas prices due to the ability of many power generators to switch between coal and gas fired electric generation.

Figure 3-3: Historic and Settled Future Commodity Prices – Oil and Natural Gas



As can be seen from the above graphs in Figure 3-1, Figure 3-2 and Figure 3-3, the market indications, as reflected by forward prices, show that natural gas is likely to retain its price advantage over incumbent fuels for the foreseeable future. Natural gas production declines in 2011 in response to low gas prices, recovery in industrial demand, growth in power generation demand and stricter environmental regulations placed on coal-fired generation going forward may lead to higher gas prices in the future. Furthermore, because of these factors, the natural gas supply and demand balance may be tighter in the future than it is currently and periods of price spikes due to supply disruptions or weather events may occur. However, because of the different supply and demand factors that influence natural gas and oil prices, natural gas is likely to retain its price advantage, on average, over oil and related product prices for the foreseeable future.

3.2.2 REGULATED PRICE OF CNG AND LNG IS LIKELY TO BE LESS VOLATILE THAN PRICE OF DIESEL OR GASOLINE

The second key benefit associated with NGV service offered by TGI is that it tends to be subject to less price volatility than diesel or gasoline. Although the underlying volatility of natural gas , oil and gasoline made similar, how these prices get reflect to customers may be somewhat different. For example, the NGV service relates to the fact that the regulated commodity and delivery rates under Rate Schedule 6 are set on a quarterly and annual basis, whereas diesel and gasoline are priced according to constant fluctuation more akin to a spot market. For fleet operators, a fixed fueling charge[27] such as $5 / GJ contributes to a smoother, more predictable net fuel price on a diesel litre equivalent basis.[28]

3.2.3 COMPETITIVE ADVANTAGE DUE TO ENVIRONMENTAL BENEFITS

There will be businesses that wish to employ measures to reduce their carbon footprint as a matter of principle. TGI's service offerings provide an option for these customers. Further, the reduced carbon output associated with CNG and LNG relative to diesel may also create competitive advantages that complement the fuel cost savings outlined above.

Businesses may be able to capitalize on the reduced carbon footprint for marketing purposes. An increasing number of municipalities and businesses have introduced procurement policies which favour clean air standards for garbage trucks and refuse haulers. Fleet operators running NGVs may hold a significant advantage in winning competitive bid contracts due to the GHG savings associated with NGVs.[29]

On that same note, other organizations may be interested in the reduced GHG emissions for their fleet in order to reduce their carbon footprint for compliance purposes, such as a public service organizations or municipalities that have signed on to be carbon neutral.

3.2.3.1 Ownership and Value of Carbon Credits

There may be additional value in monetizing GHG emission reductions as offsets should there be a suitable protocol for fuel switching from a higher carbon fuel such as diesel to natural gas. Current industry practice would see the benefit of the GHG emission reductions be attributed to the customer whose carbon footprint is being reduced, which, in this case, would be the end user. It is unlikely that validating and verifying emission reductions on an individual project basis would be cost effective for participating customers. Therefore, TGI may consider negotiating in future NGV agreements that Terasen Gas is entitled to any GHG emission

---

[27] Fueling charge would typically escalate at 2% per year over the term of the service agreement. Please refer to Section 2 of this Application for more details.

[28] The Company's response to BCUC IRs 1.11.1 and 1.11.2 in the 2010 Long Term Resource Plan proceeding contained additional detailed analysis of this price relationship.

[29] One large fleet operator, Waste Management stated "clients that want us to associate with us if we undertake these kinds of green initiatives. It's a competitive differentiator for us." http://www.vancouversun.com/news/Waste+Management+converting+garbage+trucks+from+diesel+natural/3590341/story.html#ixzz15ffJ5LPU

reductions as a result of the provision of the proposed NGV service offerings or EEC incentives for NGVs. Therefore, if multiple projects qualify, TGI could undertake, on an aggregate basis, third party validation and verification and the establishment of accepted protocols for these projects. Treatment of any carbon credits resulting from TGI's proposed NGV service offering or EEC NGV initiatives has not been resolved at this time.

3.2.4 SUMMARY

In summary, the expansion of NGV service offerings will be beneficial to potential NGV customers. The economic advantage of natural gas over conventional fuels is large and growing. Natural gas market fundamentals support the continuation of this economic advantage. The volatility of natural gas pricing under Rate Schedule 6 is less than gasoline or diesel pricing. The fact that NGV is a lower carbon alternative to diesel may create further competitive advantage for NGV operators that complement the fuel cost savings. These advantages all speak to the suitability of the Company providing an alternative that will permit more BC fleets to adopt NGV.

3.3 Proposed NGV Services Support B.C.'s Energy Objectives

The Company's proposed CNG and LNG Services require some investment in facilities, the cost of which is recovered in the contractual rates charged to the NGV customers using the facilities. In this Application, which is the first of such investments, TGI is seeking a section 44.2 "public interest" approval for the expenditures associated with the WM Agreement. The Commission, in considering the section 44.2 approval that the Company is seeking in respect of the Waste Management facilities, must consider "British Columbia's energy objectives" as defined by the *Clean Energy Act ("CEA")*. Other government policy provides context as well. TGI's investment to facilitate the WM Agreement supports British Columbia's energy objectives and government policy generally, primarily by promoting the adoption of NGVs and facilitating a reduction in Waste Management's GHG emissions[30]. TGI's future investments in refueling stations for NGV fleet customers will similarly support legislated energy objectives and government policy.

This Section addresses:

- Government policy impacting the transportation sector;
- The GHG emissions associated with the transportation sector; and

[30] GHGs are gases that, once dissipated into the atmosphere, trap infrared radiation from the sun that has been reflected from the earth's surface. In effect, the gases act like a greenhouse – hence the name. Ultimately too much GHG emission may contribute to a warmer planet and climate change. For the purpose of this Application, the most relevant GHGs are carbon dioxide (CO_2) and nitrous oxides (NO_x), which are emitted from combustion of transportation fuels.

- How TGI's investment in the facilities required to provide CNG Service to Waste Management promotes British Columbia's energy objectives.

3.3.1 GOVERNMENT POLICY IMPACTING THE TRANSPORTATION SECTOR

Federal, provincial, regional, and municipal governments are increasingly focused on addressing climate change and pollution. Governments at all levels are adopting policies favouring low-carbon energy as a key part of the solution to help achieve these goals. This Section discusses government's policy, objectives and direction at each level of government.

3.3.1.1 British Columbia Provincial Government

The provincial government has continually demonstrated interest in the implementation of more environmentally-friendly and efficient use of energy. In recent years the focus has been primarily on GHG emissions. As discussed in more detail in subsection 3.3.2 of this application, displacement of vehicles fueled by gasoline and diesel by NGVs would result in significant reduction of GHG emissions in British Columbia, as well as a reduction in other forms of pollution caused by the combustion of gasoline and diesel. The following sub-sections detail the specific provincial government actions that support, and are supported by, the Company's efforts to help displace conventionally fuelled vehicles with NGVs.

3.3.1.1.1 2007 Energy Plan

The framework for provincial energy policy is the 2007 BC Energy Plan[31]. The policies set out in the 2007 BC Energy Plan have been given effect in several pieces of legislation, including the recently passed CEA that sets out "British Columbia's energy objectives" applicable to the regulation of public utilities.[32]

The 2007 BC Energy Plan built on the 2002 Energy Plan,[33] which had focused on low electricity rates, energy security, private sector involvement in new electricity development, and environmental responsibility. The 2007 BC Energy Plan committed British Columbia to addressing climate change by harnessing clean and renewable energy to reduce overall GHG emissions, and to a renewed focus on the efficient use of energy sources. Recently, the provincial government's commitment to reducing GHG emissions and increasing the development of clean energy were re-affirmed in the February 9th, 2010 Speech from the Throne and through the passing of the *CEA*.

---

[31] "Energy Plan 2007: A Vision for Clean Energy Leadership". http://www.energyplan.gov.bc.ca/PDF/BC_Energy_Plan.pdf

[32] S.B.C. 2010, c. 22. A copy of the First Reading version of the *Clean Energy Act* is available at: http://www.leg.bc.ca/39th2nd/1st_read/gov17-1.htm
At the time of filing this Application this was the only version of the *Clean Energy Act* available on the Legislature's website.

[33] "Energy Plan 2002: Energy For Our Future: A Plan for BC". http://www.llbc.leg.bc.ca/public/pubdocs/bcdocs/357957/

The 2007 Energy Plan identified the transportation sector as “a major contributor to climate change and air quality problems”. The 2007 Energy Plan went on to observe that, based on current practices, “The fuel we use to travel around the province accounts for about 40 per cent of British Columbia’s greenhouse gas emissions”. This statement not only observes a problem, but helps identify the solution: displacing incumbent fuels with cleaner-burning fuels in the transportation sector presents the greatest opportunity by volume for a reduction in province-wide GHG emissions. The 2007 Energy Plan went on to note that “The government is committed to reducing greenhouse gas emissions from the transportation sector and has committed to adopting California’s tailpipe emission standards from greenhouse gas emissions and champion the national adoption of these standards”, a clear statement of direction that the British Columbia provincial government is serious about not just encouraging, but demanding that the transportation sector move to cleaner options. An example of a preferred cleaner option was then identified in the 2007 Energy Plan with the statement “Natural gas burns cleaner than either gasoline or propane, resulting in less air pollution.” Finally, the provincial government encouraged the use of new and innovative solutions by stating that “British Columbia will focus on research and development, demonstration projects, and marketing strategies to promote British Columbia’s technologies to the world.”

The Provincial Government has given effect to policies set out in the 2007 BC Energy Plan in legislation. Several examples follow.

3.3.1.1.2 Renewable Portfolio Standards

Renewable Portfolio Standards are requirements that any given supply, or portfolio, of a energy must be composed of a standard minimum amount of energy from a sustainable source. An example of the adoption of a Renewable Portfolio Standard by the British Columbia Provincial Government was the 2008 introduction of the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act*.[34] This act created the legal structure required to impose an escalating minimum percentage of renewable fuel in gasoline and diesel sold within the province. As of January 1, 2010, the renewable component required is 5%, and the Carbon Tax applicable to gasoline and diesel has been reduced proportionately to reflect the reduced non-renewable component of these fuels.[35]

The LCFRR mandates a 10% reduction in the carbon intensity of motor vehicle fuels used in B.C. The required reductions are phased in over time with the 10% reduction required by 2020.

Natural gas is a low carbon intensity motor vehicle fuel. The methodology adopted within the provincial regulation combines measures of the base carbon intensity of the fuel with measures of the efficiency of the engine technology that is used with the fuel. This results in an effective carbon intensity in use. Selected values for various fuels are presented in Table 3-5 below:

[34] S.B.C. 2008, c. 16.
[35] Renewable Fuels Notice – Carbon Tax. http://www.sbr.gov.bc.ca/documents_library/notices/Renewable_Fuels_Notice_Carbon_Tax.pdf

Table 3-5: Natural Gas is Less Carbon Intensive Than Conventional Fuels

Fuel	Base Carbon Intensity (gms CO_2e /MJ)	Engine Efficiency Factor	Adjusted Carbon Efficiency (gms CO_2e /MJ)
Gasoline	90.56	1.0	90.56
Ultra Low Sulphur Diesel	93.56	1.2	77.97
CNG	62.16	1.1	56.51
CNG (Digester Gas)	-3.25	1.1	-2.95
LNG	61.69	1.2	51.41
LNG (Digester Gas)	-3.25	1.2	-2.71

Source: LCFRR Intentions Paper[36]

Some key points to note:

- Conventional CNG has a net carbon intensity value that is 38% lower than reformulated gasoline and 28% lower than ultra-low sulphur diesel.
- Conventional LNG has comparable reductions in net carbon intensity

Emerging sources of Biomethane such as CNG from anaerobic digesters is fully carbon neutral, and potentially even carbon negative.

3.3.1.1.3 Greenhouse Gas Reductions Targets Act

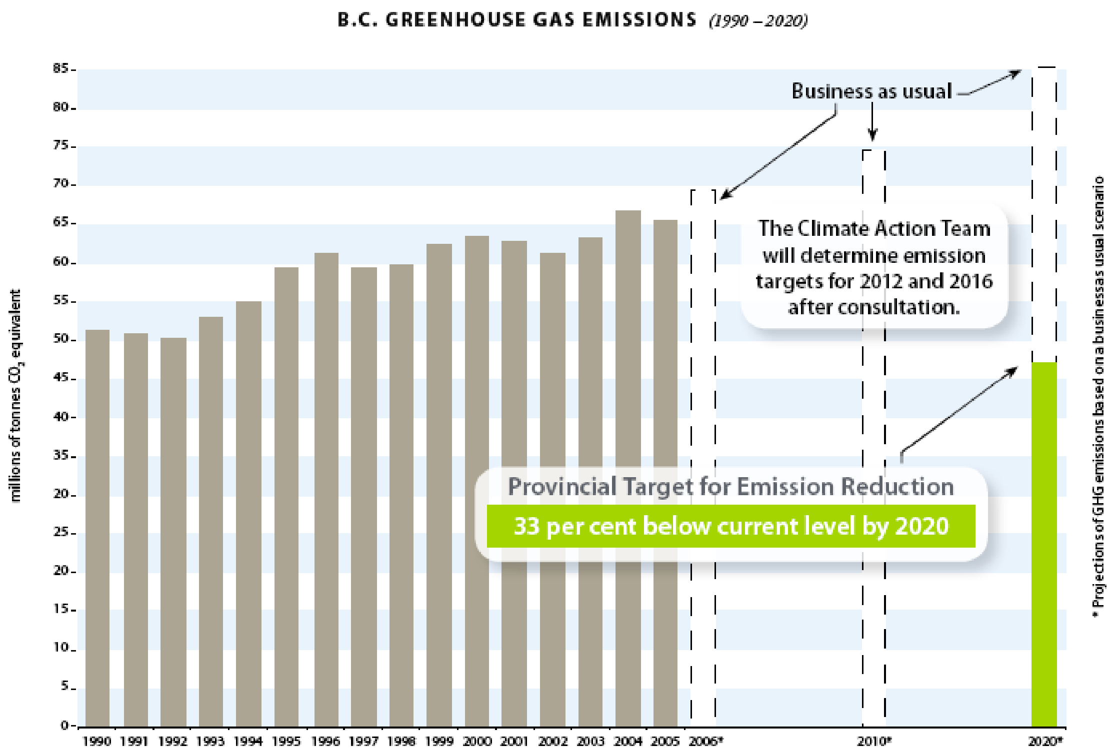
The *Greenhouse Gas Reduction Targets Act* ("GGRTA"), enacted in 2007, mandates reductions of provincial GHG emissions of thirty-three percent by 2020 and eighty percent by 2050 using 2007 as the baseline.[37] The GGRTA also requires all departments of the provincial government to become GHG neutral by 2010.

In recent years, BC's provincial government and municipalities have taken steps to develop targets and action plans to support reductions in GHG emissions. The actions of Canada's federal government, while not (yet) reflected in formal policy or legislation, reinforce this focus on cutting GHG emissions through reducing consumption of carbon based fuels. All levels of government recognize that GHG emissions reduction is a pressing need, which gives rise to an increased focus on energy policy and energy issues. The BC Government has established aggressive goals for GHG emission reductions. Figure 3-4 shows the emission reduction targets for B.C. in 2020[38].

---

[36] LCRFF Intentions Paper http://www.empr.gov.bc.ca/EEC/Strategy/BCECE/Documents/LCFRR%20Intentions%20Paper%20Final.pdf
[37] S.B.C. 2007, c. 42
[38] BC Ministry of Energy, Mines and Petroleum Resources 2009

Figure 3-4: B.C. GHG Emissions from 1990 to 2020



The Province passed Bill 44 (2007 Greenhouse Gas Reduction Target Act) in the 3rd Session of the 2007 Legislative Session. Part 1 of Bill 44 outlines BC GHG emission targets levels as being:

> *"By 2020 and for each subsequent calendar year, BC greenhouse gas emissions will be at least 33% less than the level of those emissions in 2007; and by 2050 and for each subsequent year, BC greenhouse gas emissions will be at least 80% less than the level of those emissions in 2007."*[39]

On November 25, 2008 GHG interim targets were set by Ministerial Order as follows:

- 2012 – six per cent below 2007; and
- 2016 – eighteen per cent below 2007 levels.

[39] This means that GHG's emissions within BC must be reduced by 33% from 2007 levels by 2020. This may come in the form of a physical reduction or purchasing an offset that qualifies under the regulations.

3.3.1.1.4 Carbon Tax Act

The Carbon Tax Act, passed in 2008, further signaled the provincial government's commitment to the reduction of GHG emissions.[40] As stated on the British Columbia

Ministry of Finance website, the purpose of the carbon tax "*is to ensure that a consistent long term price signal is provided to consumers so that they continue to make the choices required to reduce their fossil fuel use and emissions*."[41] The level of the carbon tax varies according to the carbon intensity of the fuel. The implementation of this tax therefore encourages the use of natural gas over gasoline and diesel through a lower rate of taxation.

3.3.1.1.5 Utilities Commission Act and Clean Energy Act

The *UCA* requires the Commission to ensure that utilities undertake efficiency and conservation measures in their operations, and to consider the British Columbia's energy objectives (as defined in the *CEA*, in specified approval processes. TGI details later in this Section how the investment in NGV fueling infrastructure to serve fleets supports British Columbia's energy objectives.

3.3.1.1.6 Natural Gas Road Tax Exemption

The British Columbia Provincial Government has explicitly encouraged the use of NGVs in the treatment of road taxes. Motor fuel tax is not applied to the natural gas used to power NGVs[42]. This explicit endorsement through subsidization of the use of natural gas as a vehicle fuel is further evidence of the government's support for NGVs, and how the aims of this application are supportive of government policy and energy objectives.

3.3.1.2 Municipal Governments in British Columbia

Local governments have responded to the provincial policy initiatives in respect of GHG reduction. On September 26, 2007, sixty-two communities across the province announced that they had signed on to the B.C. Climate Action Charter, committing to become carbon neutral by 2012.[43] By the end of 2009, 176 municipalities in B.C. (out of 188 in total) had signed the Climate Action Charter. Replacing conventionally-fueled fleet vehicles with NGVs provide municipalities an opportunity to achieve significant GHG emissions reductions.

3.3.1.3 Canadian Federal Government

Like the British Columbia provincial government, the Canadian federal government has shown increasing concern for GHG emissions, the use of renewable energy and the efficient use of energy. Examples of this concern have been demonstrated in recent environmental legislation

---

[40] S.B.C. 2008, c. 40.
[41] British Columbia Ministry of Finance: Myths and Facts About The Carbon Tax http://www.fin.gov.bc.ca/tbs/tp/climate/A6.htm
[42] http://www.sbr.gov.bc.ca/documents_library/bulletins/mft-ct_005.pdf Page 7 of 12
[43] http://www.cd.gov.bc.ca/ministry/whatsnew/climate_action_charter_update.htm

and throne speeches. Specific support of the increased use of NGVs has been building within the federal government, and is discussed below.

3.3.1.3.1 Marbek Report – Study of Opportunities for Natural Gas in the Transportation Sector

In 2009 the Fuels Policy and Programs division of Natural Resources Canada ("NRCan") commissioned Marbek, an environmental consulting firm, to produce a study[44] examining the potential benefits of and market size for increased usage of NGVs in Canada. The report found that not only was there a significant market opportunity for increased utilization of NGVs in Canada, but federal government encouragement of this market transformation could produce substantial environmental benefits including but not limited to substantial reduction of GHG emissions.

3.3.1.3.2 Natural Resources Canada ("NRCAN") Working Group

As a follow up to the Marbek study, NRCan launched a roundtable forum for potential participants in the NGV industry and other interested parties to determine what steps can be taken to encourage the adoption of NGVs in Canada. This working group was announced in March of 2010[45].

3.3.1.4 Summary of Government Policy

Governments at all levels are adopting policies in favour of low-carbon energy as a key part of the solution to help achieve their GHG emission reduction goals. The proposals in this Application are both consistent with and adherent to these policy directives, and allow Terasen Gas to be a part of the solution to these environmental challenges.

3.3.2 TRANSPORTATION SECTOR GHG EMISSIONS

Government policy relating to the reduction of GHG emissions in the Province presents a significant challenge to retaining and attracting customers who consume natural gas to produce heat. However, at the same time the policy supports the use of natural gas as a fuel in the transportation sector, which has lower associated GHG emissions than gasoline or diesel. In this Section, Terasen Gas discusses the GHG emissions that are associated with the transportation sector.

What makes B.C. unique relative to other jurisdictions regarding the output of GHG is the sources of these emissions. BC has only 2 per cent of its GHG emissions coming from the electricity sector, while at the same time producing fossil fuel (primarily natural gas) which creates additional emissions in BC. About 17% of BC GHG emissions come from the direct consumption of natural gas. This creates some challenges for BC in meeting its stated goals

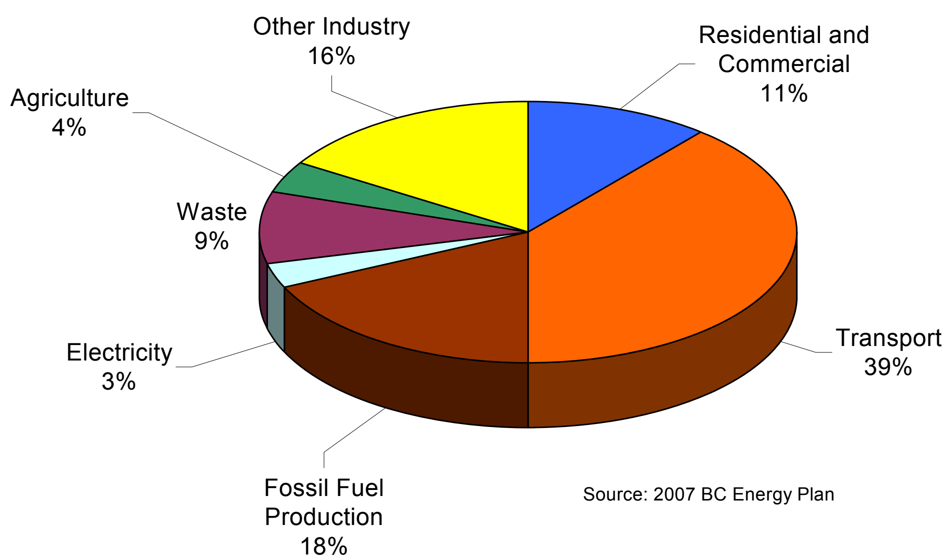
[44] "Study of Opportunities for Natural Gas in the Transportation Sector", March 2010 http://www.cngva.org/media/4302/marbek_ngv_final_report-april_2010.pdf

[45] Further description of the working group can be found on the NRCAN website at http://www.nrcan-rncan.gc.ca/com/consultation/concon-eng.php

with economic and market ready customer solutions. The use of natural gas in NGV is a solution that meets these criteria for customers.

Figure 3-5 below indicates that the single largest source of greenhouse gas in B.C. is the transport sector. Terasen Gas believes that reducing GHG emissions in the transportation sector is necessary in order to realistically achieve the provincial government's stated objectives.

Figure 3-5: B.C. Greenhouse Gas Emissions by Sector[46]



According to the 2007 BC Energy Plan, overall emissions of GHGs in BC as of 2007 was estimated at 67 million tonnes.[47] The BC Provincial GHG Inventory Report indicates that BC's transportation sector produced over 25 million tonnes ("Mt") of this total.[48] Figure 3-6 below breaks down the 25 million tones of GHG emissions from the transportation sector by each segment.

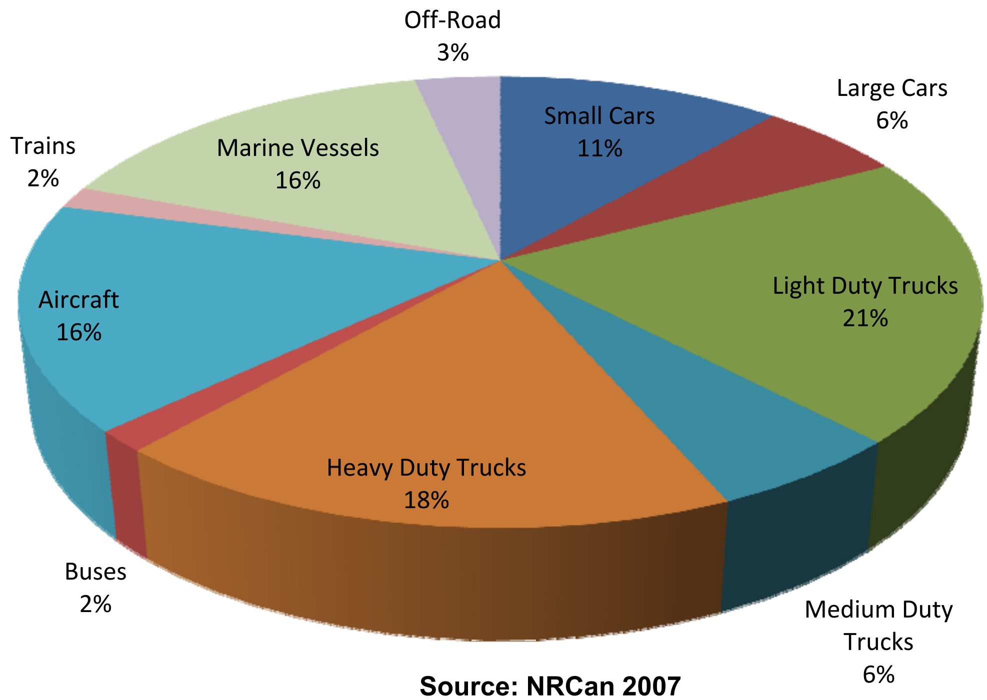
---

[46] 2007 BC Energy Plan – A Vision for Clean Energy Leadership, http://www.energyplan.gov.bc.ca/PDF/BC_Energy_Plan.pdf

[47] BC Provincial GHG Inventory Report 2007. http://www.env.gov.bc.ca/cas/mitigation/ghg_inventory/pdf/pir-2007-full-report.pdf

[48] Natural Resources Canada, Office of Energy Efficiency, 2007: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/trends_tran_bct.cfm

Figure 3-6: Trucking segments represent nearly 44% of B.C.'s transportation GHG emissions



Source: NRCan 2007

The above graph illustrates that the trucking segments (light trucks, medium truck and heavy trucks) makes up approximately 44% (or 11.4 Mt) of the total transportation emissions profile, or 17% of all GHG emissions in the province.

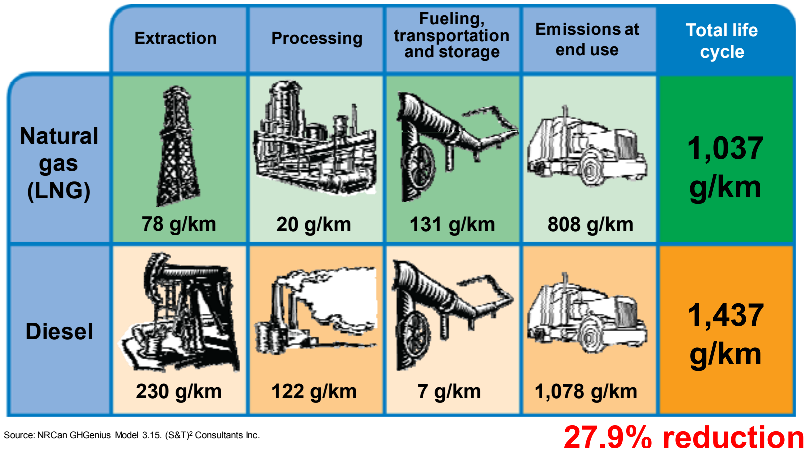
Data from NRCan indicates heavy duty NGV's emit 23 - 27% less GHG emissions than their diesel counterparts;[49] therefore adoption of NGVs in the trucking sector would have a significant impact on overall GHG emissions in BC.

For example, Figure 3-7 illustrates the GHG emission reduction on a lifecycle or "wells-to-wheels" approach of LNG versus diesel. This considers not only vehicle operation, but fuel stock production, processing, transport and storage.

---

[49] Based on BC emissions factors from Natural Resources Canada's GHGenius model 3.18 available at www.ghgenius.com

Figure 3-7: Lifecycle GHG Benefit – Westport GX-Equipped Truck – BC 2010



Source: Natural Resources Canada - *GHGenius 3.18*

Vehicle assembly, transport and materials add small incremental emissions to the lifecycle analysis, resulting in a 26.8% overall reduction. Using the same lifecycle model, the emission benefits from a vocational garbage truck running on CNG is approximately 23.2%. A light duty vehicle switching from gasoline to CNG creates a reduction of 25.6%.

Public and government interest in the environmental impact of fuel consumption, particularly as it relates to GHG emissions, should be beneficial to the growth in use of natural gas as a vehicle fuel because:

- Natural gas burns cleaner than conventional fuels and generates fewer air contaminants such as oxides of nitrogen, sulphur oxides, carbon monoxide and particulate matter. In general this means that natural gas engines require less post combustion treatment to meet emissions requirements.
- As discussed in the preceding section, natural gas is a low carbon fuel that creates far fewer greenhouse gas emissions.

In conjunction with vehicle operators, Terasen Gas has developed detailed estimates of GHG emissions reductions that will be achieved for the trucks that are most commonly used in the trucking segments. As the emissions data are reported in grams per km travelled, overall GHG emissions reductions depend on the number of vehicles operating on natural gas and the annual distance travelled by such vehicles. The results of these models indicate that GHG reductions ranging from 10 to 126 tonnes per vehicle per year are achievable by switching to natural gas.

If successful in achieving a 30 PJ market penetration, which is 6.5% of the target market, the use of NGVs should deliver 865,000 tonnes of GHG emissions reductions. Thus the use of NGVs in BC will achieve large reductions in overall GHG emissions and this will help meet

British Columbia's targets as set out in legislation, as discussed in further detail in subsection 3.3.1.1.3 of this Application.

3.3.3 TGI'S INVESTMENT SUPPORTS BRITISH COLUMBIA'S ENERGY OBJECTIVES

The Commission must consider "British Columbia's energy objectives", specified in the *Clean Energy Act*, in determining TGI's application pursuant to section 44.2 for approval of expenditures for the cost of the facilities required to provide service to Waste Management under the WM Agreement. These legislated policy objectives contemplate public utilities being engaged in achieving government policy through utility investments (sections 44.2 and 45) and supply acquisition (section 71).

A number of the "British Columbia's energy objectives", quoted below, support this Application:[50]

> (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% less than the level of those emissions in 2007,
> >
> > (ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,
> >
> > (iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,
> >
> > (iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and
> >
> > (v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;
>
> (h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;
>
> (i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;
>
> (k) to encourage economic development and the creation and retention of jobs;

In Table 3-6 below,, TGI summarizes how investment in NGV refueling facilities backed by "take-or-pay" contracts like the WM Agreement supports each of the above objectives.

---

[50] S.B.C. 2010, c. 22. A copy of the First Reading version of the *Clean Energy Act* is available at: http://www.leg.bc.ca/39th2nd/3rd_read/gov17-3.htm

Table 3-6: Service Agreement Support BC Energy Objectives

British Columbia's Energy Objective	How Proposed Service Offering Supports Energy Objective
(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	Use of low-carbon CNG and LNG engine technology developed and manufactured by BC-based Westport Innovations.
(g) to reduce BC greenhouse gas emissions…	Low-carbon NGVs in WM Agreement result in 23% fewer emissions than diesel equivalent vehicles.
(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia	WM Agreement facilitates Waste Management fuel switching from diesel to CNG. This results in approximately 214 fewer tonnes of CO2e per year.
(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently	Waste Management is replacing high-carbon, diesel emitting waste haulers - which operate in Lower Mainland communities - with low-carbon NGVs.
(k) encourage economic development and the creation and retention of jobs	Supports economic development and job creation for BC-based NGV engine manufacturer Westport Innovations, CNG station manufacturer IMW industries, and various engine conversion installers.

The proposed services are not detrimental to any of the other British Columbia's energy objectives.

3.3.4 CONCLUSION

The *Clean Energy Act* and government policy generally places a new focus on NGVs, laying the groundwork for increase in utilization of this technology in British Columbia. As British Columbia's energy objectives are applicable in the context of the regulation of public utilities, these amendments speak to the government's objective of involving public utilities in the targeted reduction of GHG emissions through the efficient development of cleaner uses of energy, such as displacing incumbent fuels with NGVs. The Company's proposed investment in the facilities to provide service to Waste Management under the WM Agreement supports British Columbia's energy objectives and government policy. TGI believes that the expenditure in support of providing service to Waste Management is in the public interest and should be approved pursuant to section 44.2 of the Act.

Fasken Martineau DuMoulin LLP *
Barristers and Solicitors
Patent and Trade-mark Agents

2900 - 550 Burrard Street
Vancouver, British Columbia, Canada V6C 0A3

604 631 3131 Telephone
604 631 3232 Facsimile

www.fasken.com

Matthew Ghikas
Direct 604 631 3191
Facsimile 604 632 3191
mghikas@fasken.com

May 25, 2011
File No.: 240148.00595/14797

ELECTRONIC FILING

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

Attention: Ms. Alanna Gillis,
Acting Commission Secretary

Dear Sirs/Mesdames:

Re: FortisBC Energy Inc. and Fortis Energy (Vancouver Island) Inc.
(the "FortisBC Energy Utilities")
Energy Efficiency and Conservation Program Natural Gas Vehicles Incentive

We enclose for filing in the above proceeding the electronic version of the Reply Submissions on behalf of FortisBC Energy Utilities.

Twelve hard copies of the Reply Submissions will follow by courier.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

[original signed by Matthew Ghikas]

Matthew Ghikas

MTG/fxm
Enc

BRITISH COLUMBIA UTILITIES COMMISSION

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

and
FortisBC Energy Inc. and
FortisBC Energy (Vancouver Island) Inc.
(the "FortisBC Energy Utilities")

ENERGY EFFICIENCY AND CONSERVATION PROGRAM

NATURAL GAS VEHICLE INCENTIVES

Reply Submission of the FortisBC Energy Utilities

May 25, 2011

1. A number of stakeholders provided letters of support to the FortisBC Energy Utilities (the "FEU" or the "Companies"), which were included in evidence and have already been referenced in the Companies' Final Submission. This Reply Submission addresses the final submissions of the Commercial Energy Consumers Association of British Columbia ("CEC"), the Ministry of Energy and Mines ("Government"), and the B.C. Sustainable Energy Association ("BCSEA"). These three parties are supportive of the position articulated by the FEU.[1] In particular:

(a) Both customer groups that filed final submissions – BCSEA and CEC (Government did not speak to this issue) – agreed with the FEU's characterization of how the EEC framework was intended to operate.[2] They agreed that customers benefit from the FEU continuing to have flexibility to manage the EEC portfolio going forward.[3]

(b) Government, BCSEA and CEC all support NGV EEC as being in the public interest. Government, for instance, provided an extensive submission detailing how the actions taken to date have supported "British Columbia's energy objectives", and the importance of eliminating the uncertainty regarding EEC funding going forward. For the reasons articulated by the FEU, and reinforced by these intervenors, the NGV EEC funding meets the requirements under section 44.2.

The overwhelming support for these initiatives underscores the need to bring this process to a conclusion as soon as possible.

2. The CEC has articulated a practical concern regarding the potential for the Commission to be "drawn into micro managing the entire EEC activity".[4] BCSEA similarly stresses the benefits of flexibility in optimizing EEC funding.[5] The FEU agree that there are key administrative efficiencies inherent in the EEC approach that the Companies submit was approved in the original EEC Decision. Accountability for how the FEU manages expenditures included within an accepted expenditure schedule is well addressed through the requirement that only prudent forecast costs are recoverable in rates,[6] which as CEC notes[7] is an analysis undertaken at the time rates are set and not before.

---

1 The FEU have focussed on the general thrust of the submissions, without taking issue with any minor nuances in wording.

2 CEC Submission, pp. 4-5; BCSEA Submission, pp. 4-6.

3 CEC Submission, p. 5; BCSEA Submission, p.4-6.

4 CEC Submission, p. 5.

5 BCSEA Submission, pp. 4-5.

6 Both CEC and BCSEA agree with the applicability of the prudence test: BCSEA Submission, p.8; CEC Submission, pp. 8-9.

7 CEC Submission, pp. 8-9.

3. BCSEA submits on pages 4-6 that the effect of the 2009 EEC Decision rejecting Innovative Technologies was to reduce the total approved envelope, and not to bar the activity or even exclude Innovative Technologies from the expenditure schedule, because the FEU were explicitly given flexibility over the portfolio spending. BCSEA's submission is analytically consistent with fact that the Commission's rate setting mandate involves fixing rates without dictating how the utility spends the resulting revenues.

4. The CEC has identified that the Commission's final order in the 2010-2011 RRA cited sections 59-61 of the Act, but not section 44.2, in the preamble to the list of orders. As the RRA and the NSA contemplated that the EEC funding approvals were being sought under section 44.2 of the Act, the rectification of the Order to include a reference to section 44.2 in the Order should be treated as a "housekeeping issue".

5. In conclusion, the FEU respectfully submit that the existing EEC framework, which preserves the Companies' flexibility to optimize the EEC portfolio, makes sense for all stakeholders. The EEC programs for NGV are in the public interest and are already, or alternatively should be, included within the scope of the currently accepted expenditure schedule as part of the Innovative Technologies Program Area. Once the uncertainty regarding the EEC framework and the NGV-related EEC programs has been resolved, the Companies expect to resume the NGV-EEC program for 2011 by extending funding to previously identified recipients and any newly identified vehicle fleets.

6. The FEU wish to reiterate that they appreciate the Commission's willingness to consider this matter on an expedited basis in recognition of the importance of the NGV-related and other EEC initiatives for all stakeholders.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

Dated: May 25, 2011

[original signed by Matthew Ghikas]
Matthew Ghikas
Counsel for FortisBC Energy Inc.

Appendix F

Thermal Energy

1. 2008 Long Term Resource Plan Excerpts
2. 2010 Long Term Resource Plan Excerpts
3. 2010-2011 TGI RRA BCUC IR1 Excerpt
4. 2012-2013 FEU RRA Excerpts
5. FEI Tariff General Terms & Conditions – Section 12A
6. EES Consulting TES Report

Developing Biogas Supply

Terasen Gas has applied for funding under the Innovative Clean Energy (ICE) Fund to develop a biogas upgrading demonstration project at Metro Vancouver's Lions Gate Waste Water Treatment Plant.

The project would provide enough carbon neutral gas to displace the natural gas usage of over 100 homes and CO2e reduction equivalent to removing 165 passenger vehicles from the road.

7.2.2.4 Developing Biogas as an Alternative Supply

One of the primary concerns for gas utilities interested in the potential of biogas is the quality and heat content of the gas produced. Terasen Gas is working with the agricultural and municipal waste sectors, as well as biogas upgrading equipment manufacturers to develop a biogas upgrading project in which the lessons learned could be used to develop future large scale projects. Such projects could help reduce the greenhouse gas emissions by capturing the methane, upgrading it and using the upgraded product as an energy source rather than being flared or vented into the atmosphere.

Terasen Gas is also evaluating various options as to how biogas will be incorporated into its supply portfolio. Current options under investigation include, using the carbon neutral gas to offset greenhouse gas emissions from compressor and other operating equipment, provide customers an opportunity to pay a premium to purchase biogas as an alternative fuel source, or incorporate the biogas into the core gas supply portfolio. Terasen Gas' objectives are to continue evaluating the biogas potential and if feasible, to help develop this new potential industry sector to allow for biogas sales, offering customers as a more sustainable augmentation to natural gas supply that will allow for a reduction in the overall carbon footprint.

7.3 Alternative Energy Systems

Alternative energy systems for space and water heating have been discussed in Chapter 2 and Appendix D in relation to the competitive position of natural gas. However, natural gas can also be an important component of these types of systems in serving both individual homes and neighbourhoods through district energy systems. Development of these technologies can also lead to the growth of distributed electricity generation facilities and technologies, which can help to meet Provincial objectives for electricity sustainability and the development of new clean and efficient sources of supply.

Terasen Gas recognizes that alternative energy systems and technology have become a part of the energy planning landscape in B.C. and that there is no single solution to meeting the growing demand for energy in the province. Hence, utilities need to examine all of the ways that both new and traditional technologies can be combined to create a diverse and robust energy portfolio for B.C and the Region.

Heat Pumps / Geo-exchange Systems

Ground source heat pumps ("GSHP") are a form of geo-exchange system. These systems can be installed in single family applications, multi-family developments and district energy systems (discussed below). Air source heat pumps are another space heating and cooling technology, although more applicable for single family applications. Both types of systems are typically installed along with a secondary or back-up energy system that is typically either an electric or a natural gas system. These systems continue to gain popularity in B.C. due to their high efficiency and more recently to home owner desires to reduce their end-use carbon footprint.

As the name implies, geo-exchange or geo-thermal systems use heat pump technology to exchange heat energy between ground, groundwater or surface water resources and the living or working environment in buildings. There also appears to be growing interest in some urban areas for heat pump technology that utilizes waste heat from other municipal systems such as sewers and sewage treatment. Geo-exchange systems are most often used for building heating and cooling and hot water and the conditions for successfully implementing this technology are very regional and site specific.

More and more, developers and community planners appear to be looking to hybrid systems that combine geo-exchange technology with other forms of both new and traditional energy technologies. These systems can be designed with building use and regional weather characteristics in mind to provide an optimal mix of energy efficiency, reduced emissions, system reliability and life cycle costs. Potential opportunities exist to leverage natural gas infrastructure to employ a range of hybrid systems for single family homes, multi-family developments and communities. Terasen Gas continues to examine the potential for such systems in its service regions where they can benefit customers, help to optimize existing infrastructure and address government policies on energy and climate change.

High-Efficiency District Energy Systems

High efficiency gas boiler technology can be combined with hydronic heating systems to improve system efficiency, reliability and life cycle costs even further. Hydronic heating systems - the circulating of heated water from a centralized source to facilitate the distribution of space heating and hot water – are a long-established and proven technology. Combined with geo-exchange and / or high efficiency gas boiler technology, these systems can provide reliable and cost-effective distribution of energy for multi-unit developments or even multi-use communities, at some of the highest possible efficiencies. The Lonsdale Energy Corporation in North Vancouver provides an example of effectively implementing this type of distributed systems by supplying an entire mixed use, downtown area of the Municipality. New high density residential, community centre and business customers continue to be added to this highly efficient system that is expected to serve 3 million square feet of building space within 10 years.[34]

District energy technology is also one way of combining natural gas with other emerging renewable technologies to create a highly efficient, sustainable and reliable mixed energy platform for growing communities. As new, renewable sources of energy are developed for a community, they can be easily exchanged within the existing district energy infrastructure, making the mixed energy platform flexible to future technologies.

<u>Dockside Green set to become North America's first greenhouse gas neutral community.</u>

At Dockside Green in Victoria B.C., a biomass gasification energy system is being employed to deliver energy to the community. The system creates low-cost heat through a thermo-chemical process known as 'starved air combustion'. This ultra-clean technology transforms locally sourced wood waste – municipal tree trimmings, mill scraps, pine-beetle damaged lumber – into energy. The process provides sufficient heat to create clean 'syngas'. Burned in a boiler just like natural gas, syngas will create heat for space and hot water needs for the 1.3 million square feet of Dockside Green's residential, office, retail and industrial space. In future, a sewer waste heat recovery system may also supplement the biomass system and utilize an otherwise wasted energy source.

<u>New Metering Technologies</u>

Growth in hydronic systems and district energy technologies is also creating a need for investment in new metering technologies in the same way that the need for individual metering in multi unit dwellings. Measuring the flow of heat and other energy to individual users in a district energy system is essential for the fair and efficient distribution of the resource and the energy costs. Terasen Gas recently received approval to develop and implement a thermal metering pilot project to assess the distribution of energy use in multi unit developments that use hydronic heating. BC Hydro has received approval for funding advanced Smart Meter technologies to improve efficiencies and help manage electricity demand. Continued investment in metering technology improvements will improve energy efficiency overall, lower the total carbon footprint in B.C. and the PNW and address Provincial energy policies.

[34] Visit the City of North Vancouver's web site at www.cnv.org for more information on Lonsdale Energy Corporation.

Distributed Generation

Small scale power generation systems and equipment located at or near the end-use is a growing choice in some regions of North America. Used primarily in commercial, industrial or institutional applications, these systems can provide peak shaving and fuel switching benefits as well as improvements in power quality and reliability for sensitive applications and remote locations.

Distributed generation equipment typically relies on traditional fuels such as natural gas at relatively high efficiencies and low emissions. However, technology advancements are allowing the use of alternate fuels such as lower quality recovered gas from industrial processes and biogas from landfills, wastewater treatment and agricultural operations. In B.C., many of the potential sources of biogas would be insufficient on their own to drive micro-turbine generators, however, when combined with pipeline supplied gas this type of generation can significantly reduce GHG emissions over the venting of biogas directly into the atmosphere.

Distributed generation provides some potentially significant benefits to the regional energy mix in circumstances where the generation facility is close to the electrical distribution network. Excess generation capacity can be supplied to the electrical distribution grid. BC Hydro, for example, does enter net metering arrangements with this type of Independent Power Producer, which can use the excess power sales to further offset energy costs. Where sufficient generation capacity can be supplied in this way, distributed generation has the potential to partially offset the need for new electrical transmission and distribution infrastructure. Natural gas can also play an important role in combined heat and power technology, which generates electricity and utilizes waste heat energy in highly efficient distributed generation applications.

Looking further into the future, improvements renewable energy technologies such as wind, run-of-river, and solar alternatives could add to the growth in distributed generation in locations where strict emission controls are in place or desired by the community. New systems, small enough and quiet enough to work in the home are being developed in Europe. Incentives from federal, provincial and local municipal governments as well as some utilities for pilot projects and implementing new technologies might speed the growth of distributed generation. Terasen Gas is ideally positioned to investigate viability of distributed generation in clean energy applications using its existing infrastructure and expertise.

7.4 Alternative Energy Conclusions

These opportunities are just a few of the emerging solutions to meet the provinces growing demand for energy and reduce the provinces carbon footprint. As a forward thinking energy utility, Terasen Gas will continue to identify alternative energy opportunities that improve efficiencies, facilitate renewable technology development and reduce carbon emissions. Where these opportunities benefit customers, help meet B.C. energy policies and utilize or optimize existing energy infrastructure, Terasen Gas will continue to investigate and pursue them.

In the transportation sector, replacing conventional transportation fuels such as diesel and gasoline provide a significant opportunity to help the province reduce greenhouse gas emissions associated with the transportation sector. The technology is proven and immediately available. To help facilitate the development of a market for natural gas in the transportation sector, Terasen Gas is undertaking a number initiatives including:

- the development of a standing tariff for the sale of LNG for use in the transportation sector,
- the provision of grants to help offset the incremental cost of natural gas vehicles,
- new technology demonstration grants, and
- working with industry partners and government lobby efforts for policy and incentive legislation.

Potential new load resulting from these initiatives is not yet considered in Terasen Gas' demand forecast; however, as markets for NGV technology in B.C. develop, the trends in load growth will be monitored and included.

Other alternative opportunities that are emerging for Terasen Gas include developing biogas projects as an alternative and renewable natural gas supply; capturing waste heat from natural gas compressors to produce electricity; and developing the use of alternative energy systems and advanced metering technologies. Terasen Gas will continue to investigate opportunities to develop these alternative, renewable supplies over the coming months for potential inclusion in utility system resource additions and supply portfolios.

3 LOW AND NO-CARBON INITIATIVES

3.1 Low Carbon Initiatives and Projects

Integrated, end-use energy solutions displace conventional fuels with low or no-carbon energy sources or systems. Terasen Utilities are pursuing integrated energy solutions in three important ways: renewable and low-carbon thermal technologies for homes, businesses and institutional facilities (the built environment); natural gas as a low carbon transportation fuel alternative to diesel and gasoline; and the development of carbon neutral biogas to displace conventional natural gas for homes, businesses and potentially in vehicles.

We believe it is in the best interest of existing and new customers that TGI provide both gas and integrated energy solutions. As such we believe that the requests set forth in this section should be approved to facilitate that development.

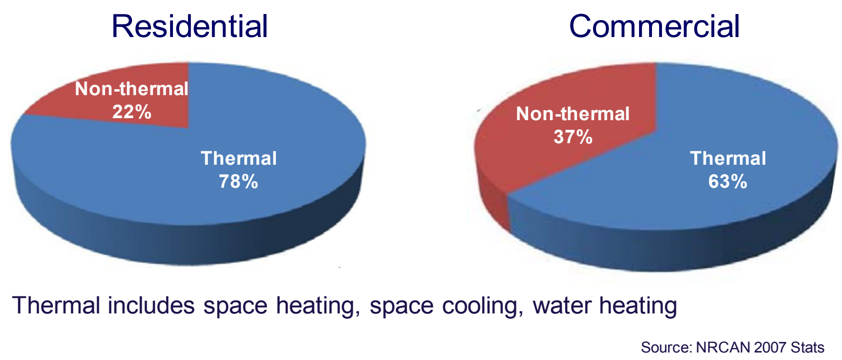
3.1.1 INTEGRATED ENERGY SYSTEMS FOR BUILDINGS AND COMMUNITIES

Geo-exchange, waste heat recovery, biomass and solar thermal energy systems are examples of integrated energy solutions that utilize thermal heating and cooling energy from the environment to replace or supplement traditional natural gas or electrically fired space and water heating systems. District energy systems use a variety of heating sources, including traditional heating sources such as gas and non traditional sources like sewage heat recovery, to deliver heating and cooling to the end use customer. The Terasen Utilities are now offering a full range of these types of efficient, low carbon intensity energy alternatives. We expect the amount of energy demand from these services to be small at first, but to grow substantially over time as more and more customers seek solutions from the utility to help reduce and manage the carbon footprint of the energy they use.

This section describes these renewable, thermal energy systems, how they meet the needs of our customers and our LTRP objectives, and the steps that the Utilities continue to take in developing the service offerings. The activities and resources described here have previously been introduced to customers, stakeholders and the Commission through the TGI and TGVI 2010-2011 RRA. Under the terms of the TGI and TGVI RRA negotiated settlement agreements, the costs of developing these systems will be recovered from integrated energy customers through future regulatory and rate setting proceedings specific to these services. As an important part of the Utilities' strategy to become an integrated provider of thermal energy services, these activities and resource needs form an integral part of the LTRP.

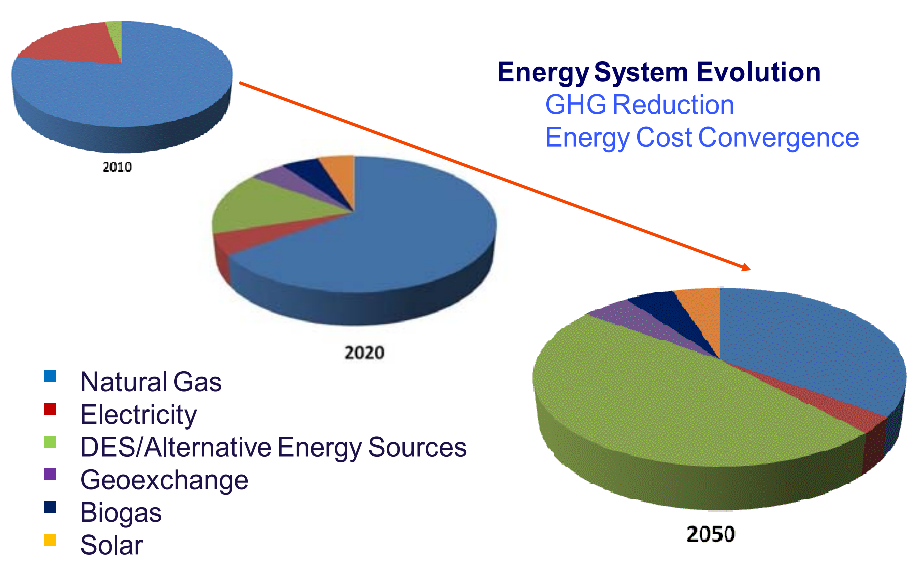
Geo-exchange and solar thermal energy systems are similar in that they utilize thermal heating and cooling energy from the environment to replace or supplement space heating and cooling and water heating served by traditional gas and electrical energy systems. District energy systems use a variety of energy sources, including traditional heating sources such as gas and non traditional sources like geo-exchange, heat recovery from industrial processes and waste management systems, biomass and solar thermal systems to deliver both heating and cooling to the end use customer. As indicated by Figure 3-1, since the bulk of energy supplied to large groups of our customers serve thermal uses, these systems have the potential to provide large portions of the province's energy needs.

Figure 3-1: Thermal vs. Non-thermal Energy Demand in B.C.



Integrated energy systems are a key part of the Terasen Utilities low carbon strategy to help existing and future customers alike cost effectively reduce the carbon footprint for their energy needs, and help meet B.C.'s overall GHG emission reduction targets. Figure 3-2 conceptually shows the important role that integrated energy will play in meeting the thermal energy and GHG reduction needs of our customers.

Figure 3-2: Transformation of Thermal Energy Delivery in B.C.

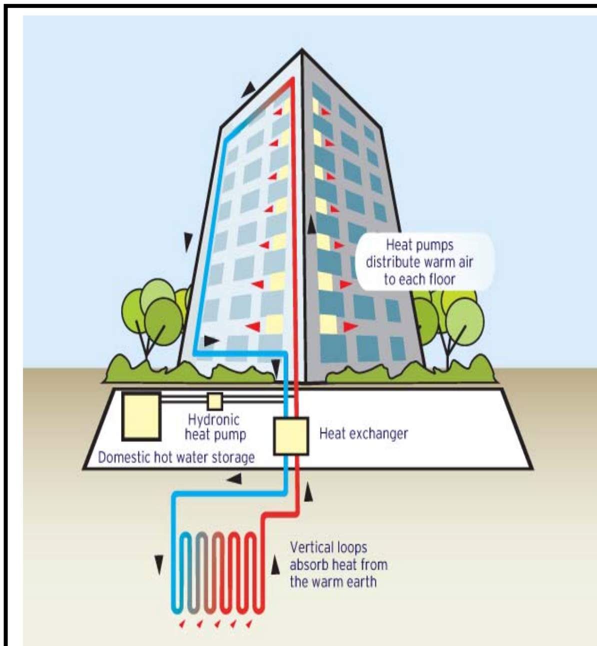


3.1.1.1 Description of Typical Integrated Energy Systems and Infrastructure

Renewable, thermal energy systems employ energy sources in variety of combinations, almost always relying on conventional energy systems to provide back-up and peaking energy service. Designing an integrated energy system that can provide 100% of peak thermal energy requirements presents both technical and economic challenges. Often, a single renewable energy source such as geo-exchange will be combined with conventional natural gas service. Multiple renewable systems can also be employed in combination with the conventional energy. For example, geo-exchange systems can provide space heating and cooling while a solar-thermal installation can provide a portion of the domestic hot water needs to the same multi-family or multi-use building. District energy systems can employ multiple energy sources and systems to balance the heating and cooling needs for a community with many end use needs. While geo-exchange and solar-thermal systems can be designed to serve single family homes, the Utilities are focusing our initiatives on larger multi-unit and district energy systems. The following descriptions of some of the systems provides an understanding of the types of equipment or infrastructure involved.

- **Geo-exchange**

Geo-exchange systems; also referred to as geo-thermal systems, earth exchange systems or ground and water source heat pumps, utilize the heat energy contained in near surface layers of the earth, ground water and surface water. A subsurface piping system contains a liquid that absorbs heat from the surrounding material and delivers it to a central heat exchanger[71]. High efficiency heat pumps convert this energy into hot water or steam contained in a separate piping system that can then deliver the heat energy to where it is required for space heating and hot water uses. Centralized equipment is usually contained within a specifically designed mechanical room that serves the entire development. The heat exchanger is reversed to provide space cooling, removing heat from the building(s) and returning it to the subsurface substrate.



[71] Typically geo-exchange systems are designed to provide 50-80% of the heat with the remaining heat provided for by a gas boiler

➢ Solar-Thermal

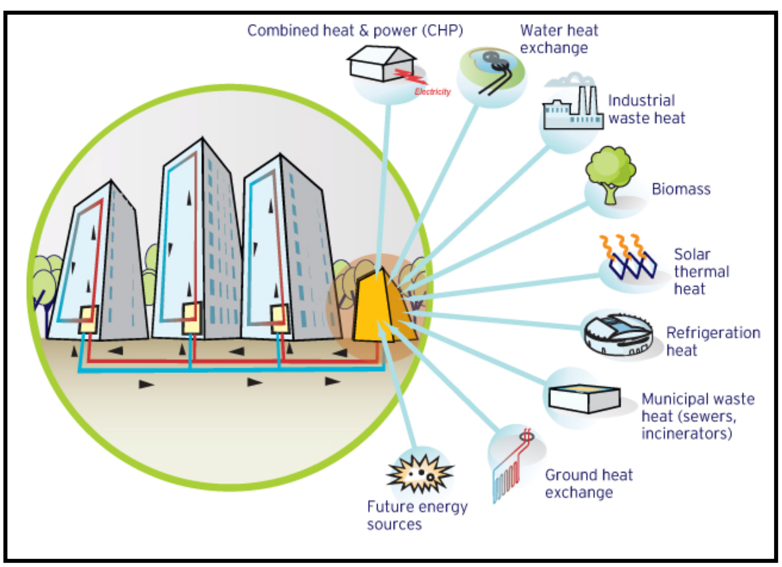
Solar-thermal water heating systems, also called solar hybrid water heating systems, are more typically used to supplement traditional gas and electric energy systems that supply domestic hot water, improving the efficiency and lowering the carbon intensity of the traditional systems. A system of solar collection tubes and piping capture heat energy from the sun's rays and deliver it to a central heat exchanger, where it is converted to DHW and distributed in a manner similar to that described above for geo-exchange systems. The solar collection tubes are located outside the building or buildings, typically on the roof, while centralized equipment is again housed in a specifically designed mechanical room.

Both geo-exchange and solar-thermal energy systems can be designed in combination with other traditional piped energy systems and metering technologies already a part of TGI's regulated service offerings. TGI's expertise with piped energy infrastructure, metering equipment and customer services combined with the current environmental and social values of customers make these systems an obvious evolution of TGI's business.

➢ District Energy

District energy systems ("DES") employ a range of energy technologies and sources to deliver piped heating (hot water) and/or cooling (ambient or chilled water) to multiple buildings and customers within a neighbourhood from a central plant location or locations. Higher efficiencies and the potential to replace or combine traditional energy systems with renewable energy sources to improve system costs and reduce GHGs are among the reasons for implementing DES. TGI views district energy as an important part of its future service offerings.

DES can use a single, traditional energy source and technology such as high efficiency natural gas boilers to deliver large volumes of piped hot water throughout a neighbourhood or community. More recent developments, however, are tending to employ multiple emerging technologies to capture latent, or waste heat from the environment, supplemented by more traditional energy sources and equipment. For example, the latent heat from wastewater effluent flows feeding a nearby sewage treatment plant can be captured and converted to useable energy in much the same way that geo-exchange systems capture and convert latent heat from below the surface. Geo-exchange and solar thermal systems, as well as systems that capture waste heat from industrial



process can also be employed. These systems are often used in combination with high efficiency natural gas or electric boilers to provide baseload or back-up heating where higher temperature steam is required for heating or industrial processes or if the heat needs to be transported over greater distances. More recently, boilers are being designed to use biofuels such as wood wastes to reduce reliance on fossil fuel use. The centralization of equipment makes higher efficiency equipment more economic and reduces or removes the need for individual boilers, furnaces or other space and water heating equipment within each individual unit.

The combination of fuel sources and technologies employed by each DES will be unique, but most DES projects will have common elements. Heat capture systems include a separate piping system that captures the heat energy from its source, similar to those described for geo-exchange systems. One or more central plants are located in specifically designed mechanical rooms or buildings, housing boilers, heat exchangers, pumps and piping infrastructure. Piping systems will then distribute hot water and/or steam to multiple buildings and customers within the DES service area. Finally, each building or unit served by the DES may contain specific equipment to convert the distributed steam or hot water into useable energy specific to the needs of that customer. TGI's experience with DES and expertise in providing piped energy systems make DES a natural extension of its current service offerings.

3.1.1.2 Target Market

- **Geo-exchange and Solar Thermal**

Initially, TGI expects to provide geo-exchange and solar-thermal heating equipment and services to owners and/or operators of larger single or multi-use buildings including municipal, institutional, multifamily residential and commercial end users. Such a system or systems may serve one or a few buildings, but differ from district energy systems (see discussion in the next section) in scale, scope and complexity of the energy systems. Both installation and/or ongoing O&M for geo-exchange and solar-thermal heating systems can be provided either directly by TGI or through yet-to-be-identified alliance partners such as engineering service providers. TGI does not at this time expect to provide mass market geo-exchange or solar-thermal services to individual home owners, but may in the future. The target customers of this offering would be charged rates that would recover TGI's cost of service as described in the in the paragraphs which follow on Tariff Considerations and Economic Assessment.

- **District Energy Systems**

DES can serve a range of building use types (multi-family residential, commercial, industrial and institutional) and customers. Since DES are generally designed to serve multi-use neighbourhoods or communities, there are two levels of target markets to consider – the land use planner or developer, and the ultimate end-use customer. Safety, security and reliability are all highly valued by both of these target markets, making TGI an ideal utility to provide DES services and infrastructure.

> **Quesnel Community Energy System: First of its Kind in North America**
>
> As of July 2010, letters of intent has been signed for the Quesnel Community Energy System, a biomass system that will generate ***both heat and power*** by capturing waste heat and left-over residues from an existing sawmill.
>
> **Participants**
> - Terasen Gas Inc.
> - The City of Quesnel
> - West Fraser Mills Ltd.
> - BC Hydro
>
> **Costs**
> Approximately $14 million in capital costs
>
> **Benefits**
> Based on 1.7MW of power production and heat service to 14 buildings initially, the QCES will:
> - Reduce greenhouse gas emissions by 6,000 tonnes per year.
> - Produce 81,000 gigajoules per year of carbon-neutral heat.
> - Generate 14.2 gigawatt hours per year of clean electricity.

Municipalities seeking to improve energy efficiency and reduce carbon emissions in their communities are among the proponents who will support the development of DES. Larger municipal buildings such as offices or recreational facilities might become anchor customers for DES, which are then expanded to serve other nearby customers as well. Similarly, large institutional customers, around which a host of similar land uses usually develop, could become anchor customers for a DES. Land developers might also seek DES to serve high density, mixed use developments being planned in urban locations.

Once a community with a DES is developed, the end use energy customers would be a range of building owners and tenants. These customers would be charged utility rates that would cover TGI's cost of service as described in paragraphs which follow on Tariff Considerations and Economic Assessment.

3.1.1.3 TGI's Next Steps in Delivering Integrated Energy Services

TGI will continue to provide integrated energy products for our customers. In order to achieve this TGI will:

- continue to work with customers in defining and developing their integrated energy needs;
- develop business, regulatory and operational models in which to deliver integrated energy to our customers; and
- submit an application to the Commission which will seek approval of an overall business and regulatory model and seek CPCN approval of specific projects.

6.0 Reference: Offset Emissions Regulation

Exhibit B-1, Chapter 2, p. 44

Pacific Carbon Trust

6.1 The Application states that the Pacific Carbon Trust acquires GHG offsets from projects that are located in B.C. and that meet provincial eligibility criteria. Please provide the PCT offset selling price and comment if the carbon offset price is the same input price to Terasen Utilities' own bioenergy strategy discussed in section 2.2.3.7.

Response:

The bioenergy strategy discussed in section 2.2.3.7 of the Application is the B.C. Bioenergy Strategy released by the Province (see Exhibit B-1, Appendix A-3).

The Pacific Carbon Trust indicates that they have initially set an offset selling price at $25 / Tonne[6]. The Terasen Utilities have not used the cost of offsets from the Pacific Carbon Trust in its own bioenergy strategy as the intent of TGI's proposed biomethane program is not to sell customers a marketable carbon offset, but rather a certain amount of renewable energy per GJ which, in turn, reduces their carbon footprint.

The current regulation is unclear about carbon offset opportunities for Terasen Utilities' customers. As indicated in the Biomethane Response to Workshop Undertaking, dated July 8, 2010, TGI may look at creating offsets on the customers' behalf in the future as a result of the offset created by consuming Biomethane in place of natural gas. However, this would involve third party validation and verification and the establishment of accepted protocols for these projects which have not been defined at this time, and would be a more appropriate exercise if TGI were to develop a carbon offset program, rather than the proposed renewable energy-based program. By displacing natural gas with Biomethane in end-use applications, all else being equal, there is a net reduction in the amount of GHGs which is the green attribute that customers would be paying for under the proposed program.

Please also refer to the Attachment 6.1 which includes excerpts from the TGI Biomethane Application, Exhibit B-2-1, Response to Workshop Undertaking and Exhibit B-7, Response to BCSEA IR 1.20.2.

[6] http://www.pacificcarbontrust.com/BuyOffsetsfromPCT/tabid/64/Default.aspx

23.0 Reference: EEC and Alternative Energy

Part III, Section C, Tab 3, p. 227

23.1 On page 234 of the Application, Terasen Gas states that: "TGI has…evaluated the market and need for innovative technologies."

23.1.1 Please provide all supporting evidence to suggest that TGI's customers have not only an interest but a demand for alternative energy sources. Please quantify where possible.

<u>Response:</u>

The statement referenced speaks to the "market and need for innovative technologies", an EEC program, however the question following speaks to a demand for alternative energy sources. As noted in response to BCUC IR 1.21.1, Innovative Technology requests are for EEC funding in this case to provide incentives for reducing energy usage. In contrast, we have proposed to enter into the Alternative Energy Solution market whereby TGI will own and operate components of NGV compression, biogas facilities, alternative energy delivery systems (geo-exchange, solar thermal and DES) and in turn sell customers heat or compression and purchase biogas. This response will cover both those customers who may be interested in EEC activities such as the Innovative Technology requests (incentives for hydronic systems, integrated systems, solar thermal systems, geothermal systems) as well as customers who are interested in and have a demand for Alternative Energy Solutions provided by, owned and operated by TGI.

We believe that there is substantial demand from customers[4] for alternative energy solutions provided by the Terasen Gas Inc. regulated utility. This is demonstrated by contact with customers through sales and account management activities and through three separate studies. A further discussion is provided below.

During the normal course of sales, account management activities, and community and government relations activities, our staff are speaking with existing and potential customers regarding their or their constituents use of natural gas and the role of TGI in providing energy for the province. During these discussions, more and more, customers and stakeholders would initiate conversations regarding "alternate energy sources". Customers and stakeholders have shared with the TGI staff that they were considering such technology as Geo-thermal exchange,

[4] In this response the term "Customer" means developers, engineers, architects, commercial and industrial customers, institutional customers and municipal and government stakeholders, and to a limited extent end use residential customers. This "Customer" group represents those in the marketplace who are the key decision makers determining the type of energy a building will use. In the case of developers, engineers and architects, this group represents thousands of end use customers who purchase a home with the energy choice selected by the developer.

bio gas, bio mass, waste heat recovery, district energy systems, solar and combined heat and energy systems and in addition are looking for ways to not only reduce energy consumption but reduce GHG emissions. Our staff were often challenged to compete with this technology, and to convince stakeholders how natural gas could help reduce emissions. From a sales standpoint many times this would lead to loosing the opportunity to service the customer with Natural Gas as their final decision would often be to go with an alternative energy source supplemented with electricity.

However, since 2008, TGI has begun to change its corporate focus into becoming a provider of energy rather than simply a natural gas delivery company. Stakeholders and customers have been very supportive of this change in direction for the company. In fact, there are very few customers and stakeholders with whom we have spoken that react negatively to TGI providing alternative energy solutions. Customers and stakeholders have not indicated any confusion or concern as to why a gas utility is proposing to offer alternative energy solutions. To the contrary, on average, customers and stakeholders see this corporate change as a logical move given the changing energy environment and applaud TGI for its forward looking approach. Business customers and stakeholders further understand that in today's carbon constrained world, if TGI does not adapt to the new market realities they will become akin to GM or Chrysler, formerly large companies who failed to adapt to a changing market. The effect of failing to adapt is lower gas delivery volumes and fewer customers that must pay for existing assets resulting in higher rates for all remaining customers.

Attachment 23.1.1 includes three documents, which demonstrate that customers are interested in and believe that TGI should not only move into alternative energy solutions but should be the provider of these services in a regulated environment.

The first document in Attachment 23.1.1 is a list of customers that have interacted with TGI sales, account management, market development and community/government relations staff over the past six months. This list demonstrates that 211 customers believe that TGI should provide alternative energy solutions.

The second part of Attachment 23.1.1 includes a report of a third party survey performed by TNS Canadian Facts on behalf of TGI. For the report 14 customer interviews were conducted and interviews performed. The result of these interviews is that customers expect TGI to enter into the Alternative Energy Solutions market and welcome the opportunity to work with TGI to increase energy efficiency and reduce energy usage, via these new solutions.

The third report is part of an omnibus survey undertaken by Ipsos Reid, on behalf of TGI, that surveyed 800 residential customers to determine their understanding of alternative energy and whether or not TGI should provide alternative energy solutions for customers. The results of the survey show that only 19% of customers did not feel that TGI should provide Alternative Energy Solutions. Of the remaining 81%, 33% felt that TGI should provide the solutions, 33% believed that TGI should "maybe" provide the solutions, and 12% did not know. Drilling down further in the data, it shows that the younger the responder, the more supportive they are of TGI providing these solutions. In the 18-34 age group 46% believe TGI should provide Alternative Energy Solutions, whereas in the 55+ demographic, only 24% of respondents believe that TGI should provide Alternative Energy Solutions. Overall, only 13% of those in the 18-34 demographic believe that TGI should not provide Alternative Energy Solutions. TGI believes this is a very strong endorsement of its desire to provide Alternative Energy Solutions. Further, those in the younger demographics are those individuals that are more apt to enter the housing market and therefore require energy delivery service. TGI believes that this survey shows that the individuals surveyed, which would be those who would today receive service under Rate Schedule 1, believe TGI should provide Alternative Energy Service.

23.1.2 What is the estimate number of customer additions for each test year relating to this innovative technology as described in the above statement.

Response:

As noted in response to BCUC IR 1.23.1.1, Innovative Technologies are an EEC program (i.e. not one of the Alternative Energy Solutions) whereby customers will receive incentives for Hydronic Heating Systems, Integrated Energy Systems, Solar Thermal and Ground Source Heat Pumps. These programs do not necessarily have a direct relation to the addition of customers on the Gas system. In some cases customers may be added, in others customer may already be on the system and simply be supplementing or changing their heating appliances in their home.

Appendix G

NON RATE BASE DEFERRAL ACCOUNTS

1 OVERVIEW

The FortisBC Energy Utilities maintain both rate base and non rate base deferral accounts. The recommendation for one treatment over the other has primarily been one of timing, or as a means to stream cost recovery to a particular customer or group of customers separate from all other customers. In the case of a timing issue, if the FBU are able to forecast balances for deferral accounts and include them in revenue requirements, then that is the preferred treatment. In situations where the rates for a particular year have already been set and costs need to be recorded in a deferral account, that deferral account will be non-rate base attracting AFUDC until such time as rates are re-set under the next revenue requirement, and the account is rolled into rate base. Consistent with the Uniform System of Accounts, items that are recoverable from customers but not included in rate base (such as Work in Progress or non-rate base deferral accounts) are afforded AFUDC treatment so that the utility is afforded the opportunity to earn a fair return on costs prudently incurred to provide service to customers.

The following two sections discuss the existing non rate base deferral accounts for the Mainland and Vancouver Island. Neither Whistler nor Fort Nelson have non rate base deferral accounts.

2 MAINLAND

2.1 Biomethane Variance Account (BVA)

The Commission approved the creation of the BVA in its Order No. G-194-10, to capture costs to procure and process consumable biomethane gas as well as revenues collected through the biomethane energy recovery component of rates. The BVA captures biomethane commodity costs, the capital cost of service of the upgrader plant[1], O&M associated with the upgrader plant and O&M costs attributable to biomethane customer enrolment, account finalization and billing adjustments. The balance in the BVA is recovered through the Biomethane Energy Recovery Charge. Please refer to Appendix J for a comprehensive report on the biomethane program and details regarding the balance of all deferral accounts associated with biomethane.

2.2 Commodity Unbundling

At the end of 2010, the Commercial Commodity Unbundling deferral had a balance of $52.3 thousand, and the Residential Commodity Unbundling deferral had a balance of $102 thousand. Both of these deferral accounts are forecast to have a zero balance at the end of 2011, as the currently approved Rider 8 is forecast to recover the balance in the accounts. FEI projects that the marketer fee recoveries for these programs in the future will be sufficient to recover the ongoing costs, and is therefore requesting that these accounts be discontinued effective January 1, 2012. The costs and recoveries will be recorded in O&M starting in 2012, and have

[1] As discussed in Section 5.5, Biomethane Recoveries are included in other revenue and transfer the capital cost of service of the upgrader plant from the delivery margin to the BVA

been forecast as net zero for this RRA, with the exception of the Customer Choice program expenditures which are included in the Customer Service department O&M discussed in Section 5.3.7.

2.3 Tilbury Property Purchase (Subdividable Land)

Approved by Commission Order No. G-68-10, the Tilbury Property Purchase deferral account had a balance of $3.353 million at the end of 2010. This represents the original allocation of the subdividable area ($3.3 million) plus interest recorded to date. As identified in the Tilbury CPCN application, and as required by Order G-68-10, FEI was to investigate opportunities to subdivide and sell a portion of the Tilbury Property not required for compliance purposes. On December 1, 2010, in compliance with Order G-68-10, FEI filed its semi-annual report with respect to its efforts to subdivide and sell a portion of the Tilbury Property. FEI continues to work with several parties and expects to file an application for approval of a subdivision and sale sometime before year end. The disposition of the Tilbury Property Purchase deferral account will be dealt with as part of that subdivision and sale application.

2.4 Thermal Energy Services[2] (formerly Alternative Energy Services)

FEI continues to work with customers in defining and developing their integrated energy needs. In response to those needs, development is underway on several Thermal Energy Services projects. FEI will be seeking appropriate Commission approvals for each project pursuant to item 8 of the Negotiated Settlement Agreement approved by Order G-141-09, dated November 26, 2009. These projects will come forward for BCUC approval once contracts are in place with customers. FEI expects to begin filing these contracts in the Spring or Summer of 2011 with the BCUC.

The market interest for Thermal Energy solutions is considerable. FEI currently has over 20 projects in development with a total estimated value exceeding $250 million. Several of these projects are anticipated to be submitted to the BCUC for approval in the near term. Table G-1 provides examples of some of the current Thermal Energy Services projects under development.

Table G-1: Customers are Seeking Complete Integrated Energy Solutions

Project	Description
Quesnel District Energy System, Quesnel, B.C.	FEI is developing a combined power and district heating project in the City. The project will use waste heat from the nearby pulp and paper mill to heat up to 22 buildings and generate about 1.7 megawatts of electricity. Natural gas will also continue to be an important part of the City's energy mix.

2 Thermal Energy Services means Geoexchange, Solar-thermal and District Energy Systems.

Project	Description
The Village at Fraser Mills, Coquitlam, B.C.	This district energy system will serve a new mixed-use community of up to 3,700 residential units; 150,000 square feet of commercial space; 100,000 square feet of institutional space; 235,000 square feet of industrial space; and a 44,000 square foot community building. The integrated energy solution being developed by FEI will include renewable thermal energy technology such as biomass or groundwater geoexchange.
Delta School District Geoexchange System, Delta, B.C.	FEI has an agreement with the Delta School District for the delivery of cleaner thermal energy for 17 schools and two school district buildings through the implementation of state-of-the-art geoexchange systems and high-efficiency condensing boilers, which will replace aging heating plants at school district sites. These systems provide many benefits, ranging from saving energy and improving indoor comfort to stable energy rates and a smaller carbon footprint.
City Centre and Pandosy Energy Systems, Kelowna, B.C.	FortisBC and the City of Kelowna have agreed in principle to develop two district energy systems. These FEI -owned and operated systems will use waste heat and water from the City's wastewater plant and a nearby industry as part of an integrated energy approach that can potentially save about 16,300 tonnes of CO2 per year – equivalent to removing approximately 3,500 cars from the road annually – according to the City's 2010 pre-feasibility study.

The Thermal Energy Services Deferral account was approved by Commission Order No. G-141-09 to capture and record revenues and costs related to geo-exchange, solar-thermal and district energy systems. FEI is proposing to continue segregating all costs and recoveries in this manner and is seeking approval for the continuation of the Thermal Energy Service Deferral Account in this Application. The recovery from Thermal Energy Services customers of the balance in this deferral account will be considered in FEI's future applications regarding individual contracts for approval by the BCUC. Consistent with the terms of the NSA, there are three components of costs charged to this deferral account, which are discussed in the following sections and include:

- Direct costs;
- Sales and marketing O&M and business development costs; and
- An overhead allocation from FEI.

All costs associated with Thermal Energy Services are included in the deferral account. Table G-2 summarizes the forecast costs added to the deferral account and attributable to Thermal Energy Services for 2010 and 2011, as agreed upon in the NSA, and also provides a comparison to the actual 2010 costs and the projected 2011 costs.

Table G-2: Thermal Energy Projects are in Development Stages

	2010			2011		
	NSA	Actual	Variance	NSA	Projected	Variance
Direct Costs	-	1,196	1,196	-	11,750	11,750
Sales & Marketing	1,000	1,435	435	1,500	1,550	50
Overhead Allocation	500	500	-	500	500	-
AFUDC	-	82	82	-	100	100
Tax	(428)	(682)	(254)	(530)	(543)	(13)
	1,073	2,530	1,458	1,470	13,357	11,887

2.4.1 THERMAL ENERGY SERVICES - DIRECT COSTS

The direct costs include feasibility assessment, design, equipment and construction of the various thermal energy solutions. These costs vary with the number, nature and development stage of projects. As such, an approved spending amount was not specified for 2010 and 2011 and a variance is therefore not reported. The increase in 2011 over 2010 is attributable to increased market interest in certain sectors such as schools and hospitals, with some projects beginning construction in 2011. These projects will be brought forward for BCUC approval in 2011.

2.4.2 THERMAL ENERGY SERVICES - SALES AND MARKETING O&M AND BUSINESS DEVELOPMENT

Sales and marketing O&M includes the labour of the 12 employees in Thermal Energy Services in 2011 as well as the direct labour charged through timesheets from individuals in other areas of the Companies. The costs also include contributions to industry associations of $15 thousand in 2011.[3] As agreed to in the NSA, these costs were budgeted at $1 million in 2010 and $1.5 million in 2011. As shown in Table G-2, the O&M and Business Development costs captured in the deferral account were $1.4 million in 2010 and are projected to be $1.6 million in 2011.

2.4.3 OVERHEAD ALLOCATION

In Commission Order G-141-09, FEI agreed to charge Alternative Energy Services customers $0.5 million for 2010 and $0.5 million for 2011 for administrative services provided by the gas utility to the alternative energy customers. As part of this application, FEI undertook a review of which services should be included in this administrative charge and what the charge should be for 2012 and 2013. Administrative services include those services not directly charged or chargeable and include the following categories:

- Executive: time to review current status of projects, monitor status of projects and reviewing and approving potential projects.

[3] Contributions of $5 thousand to The Canadian District Energy Association, The Community Energy Association and Geoexchange BC for a total of $15 thousand in 2011.

- Finance: management and financial reporting and accounts payable.
- Regulatory affairs: reviewing cost of service models, tariffs and project management
- Human Resources: recruiting and compensation and benefits.
- Information technology: IT support to existing employees charging time directly to the Thermal Energy Services deferral.
- Facilities: allocation of facilities costs for employees charging directly into the Thermal Energy Services deferral account. The facilities include space in the Surrey Operations Centre, Garbally/Langford and the Burnaby facility.

Based on the review, FEI has estimated that a charge of $0.5 million for both 2012 and 2013 be included as a recovery of overheads for the benefit of FEI and its ratepayers. This charge represents the expected administrative costs of supporting the Thermal Energy Services businesses.

2.5 Mark to Market – Hedging Transactions

This deferral account was approved by Commission Order No. E-22-95 to record the mark-to-market adjustment due to financial hedging transactions for System and Non-System Gas purchasing. The balance at the end of 2010 was $115.6 million credit.

2.6 Mark to Market – Customer Care Enhancement Project

This deferral account was approved by Commission Order No. G-96-10 to record mark-to-market adjustments due to fluctuations in rates on the foreign currency exchange forward contract for the CCE Project. The balance at the end of 2010 was $189.7 thousand debit.

2.7 Non Rate Base Deferrals Entering Rate Base in 2012

The following is a list of all of the non rate base deferral accounts that will be entering rate base in 2012. A discussion of each of these accounts is included in Section 6.3.

a) Tilbury Property Purchase (Land Retained)[4]
b) CCE Project Deferred O&M and Cost of Service (with allocation to Vancouver Island and Whistler)
c) Kootenay River Cost of Service
d) 2010-2011 Biomethane Program Costs
e) 2011 CNG and LNG Service Costs and Recoveries

[4] This account transfers to rate base through the appropriate Land account and is included in gross plant in 2012 as shown in Section 7, Tab 7.1, Schedule 46, Column 3, row 29

f) Residual Deferral - Rider 2 ROE Revenue Requirement Volume Variance

g) Residual Deferral – Rider 4 Delivery Refund Rider Volume Variance

h) Residual Deferral – Rider 4 Lochburn Land Costs Volume Variance

3 VANCOUVER ISLAND

3.1 Rate Stabilization Deferral Account

At the end of 2010, the balance in the Rate Stabilization Deferral Account ("RSDA") was $35.618 million. Commission Order No. G-140-09 approved the creation of the RSDA. to capture the differences in 2010 and 2011 between the net revenues received and the actual cost of service, excluding O&M variances from forecast, with the balance in the RSDA being amortized into cost of service after 2011 to offset future rate increases. Further discussion of the treatment of this account for 2012 and 2013 is included in Section 3.

3.2 Mark to Market – Hedging Transactions

This deferral account was approved by Commission Order No. E-22-95, to record the mark-to-market adjustment due to financial hedging transactions for System and Non-System Gas purchasing. The balance at the end of 2010 was $46 million credit.

3.3 Mark to Market - LNG Facility

This deferral account was approved by Commission Order No. C-9-07 to record currency exchange differences for the Mt Hayes LNG Project for an amount of contracted US dollar purchases expected to be $50 million USD. The balance at the end of 2010 was $48.8 thousand credit.

3. Reference: FEU Response to BCUC IR No. 159.0

Exhibit B-1, Application, Appendix G

Thermal Energy Projects – Overhead Allocation

Request:

3.1 Does the proposed allocation of $0.5 million to TES customers for the benefits provided by FEI include any allowance for the following benefits:

(a) communications and public relations,

(b) government relations,

(c) investor relations,

(d) treasury services,

(e) accounting advice,

(f) coporate governance, records and legal service,

(g) access to insurance at favourable rates,

(h) access to a stronger credit rating and debt at favourable rates,

(i) access to utility infrastructure, equipment and expertise, or

(j) goodwill based on the company name and profile?

Response:

This response addresses the responses to Corix IRs 2.3.1, 2.3.2 and 2.3.3. The FEU, when allocating shared services or corporate costs typically use an allocation methodology such as the Massachusetts model which relies on operating revenues, gross payroll and average tangible assets. As the thermal energy class of service is still in its early stages of development, however, such an allocation method would yield little if any allocation of costs to the thermal energy class of service. The FEU recognize that certain resources are used by thermal energy class of service, and therefore have adopted a different allocation involving allocating to the thermal energy class of service those resources that are likely to be utilized by thermal energy class of service. This ensures that a reasonable proportion of shared costs are allocated to the thermal energy class of service.

In terms of what specifically is included in the shared services subject to allocation:

(a) Yes, there is an allocation for communications, and public and government relations. The allocated cost is $35,000 each year.

(b) See the response to (a) above. The allocated amount is included within the $35,000.

(c) There is no allocation for investor relations. Given its infancy, there is no investor relations activity related to the thermal energy class of service.

(d) Yes, there is an allocation of treasury services. The allocation is $8,500 each year and includes treasury services and oversight for financial reporting.

(e) Yes, there is an allocation for accounting services, including accounting advice, which is $34,200 each year.

(f) There is no allocation of corporate governance (including Board of Directors), records and legal services: for corporate governance and records, as indicated in the preamble to this response, the charge would have yielded zero based on the Massachusetts allocation model. The time and effort spent on the thermal energy business by the Board is negligible given the current investment in thermal energy assets, therefore an allocation of zero is also supported under our proposed methodology. Legal services will be directly charged to the deferral account.

(g) No, FEI is the legal entity undertaking this business and therefore, any insurance procured would reflect the cost available to FEI.

(h) No, FEI is the legal entity undertaking this business and therefore, the credit ratings and borrowing costs of FEI would be those that are applicable.

(i) Yes, there is an allocation for facilities space and IT resources. As all direct wages are charged to the deferral account, thermal energy services is already charged for utility expertise. Included in the overhead charge is $222,000 each year for facilities space in the Surrey Operations Centre and Garbally. Additionally, information technology resources have an allocation of $51,500 for IT resources, hardware and software.

(j) No. There is no recovery for goodwill. Typically, goodwill is not recovered in cost of service based utility rates.

As noted, the $0.5 million allocation annually is intended to result in an appropriate proportion of indirect costs being deducted from the natural gas revenue requirements and allocated to the thermal energy class of service. They yield similar results in both 2012 and 2013.

3.2 If the answer is yes to any of the items in 3.1, quantify the amount.

Response:

Please refer to the response to Corix IR 2.3.1.

3.3 If the answer is no, explain why not.

Response:

Please refer to the response to Corix IR 2.3.1.

12A. Alternative Energy Extensions

12A.1 **System Expansion** - FortisBC Energy will make extensions to the FortisBC Energy System using technology that produces alternative energy, in accordance with the provisions of this section. The alternative energy extensions include geo-exchange, solar-thermal and district energy systems which are described below:

Geo-exchange systems, also referred to as geo-thermal systems, earth exchange systems or ground and water source heat pumps, utilize the latent heat energy contained in near surface layers of the earth, ground water and surface water. A subsurface piping system contains a liquid that absorbs heat from the surrounding material and delivers it to a central heat exchanger. High efficiency heat pumps convert this latent energy into hot water or steam contained in a separate piping system that can then deliver the heat energy to where it is required for space heating and hot water uses. Centralized equipment is usually contained within specifically designed mechanical room that serves the entire development. The heat exchanger is reversed to provide space cooling, removing heat from the building(s) and returning it to the subsurface substrate.

Solar-thermal water heating systems, also called solar hybrid water heating systems, are a system of solar collection tubes and piping capture heat energy from the suns rays and deliver it to a central heat exchanger, where it is converted to domestic hot water and distributed in a manner similar to that described above for geo-exchange systems. The solar collection tubes are located outside the building or buildings, typically on the roof, while centralized equipment is again housed in a specifically designed mechanical room.

District energy systems employ a range of energy technologies and sources to deliver piped heating (steam or hot water) and/or cooling (cool water) to multiple buildings and customers within a neighbourhood from a central plant location or locations.

12A.2 **Ownership** - All alternative energy extensions will remain the property of FortisBC Energy.

12A.3 **Cost of Service Model** - All applications by Customers for service using an alternative energy extension will be subject to review using a cost of service model. The cost of service model will determine the rate that a customer will pay for the service associated with the alternative energy extension. Service will be provided under the terms and conditions of the Service Agreement between FortisBC Energy and the Customer.

12A.4 **Projected Energy Consumption/Number of Customers** - The projected energy consumption and number of customers to be used in the cost of service model will be determined by FortisBC Energy by

(a) estimating the number of Customers to be served by the alternative energy extension;

(b) if applicable, establishing consumption estimates for each Customer; and

(c) projecting when the Customer will be connected to the alternative energy extension.

If applicable, the projection will take into consideration the estimated number and type of thermal appliances used and the effect variations in weather conditions throughout the applicable Service Area have on consumption. All Customers expected to connect to the alternative energy extension will be considered in the cost of service model.

12A.5 **Costs** - The total costs to be used in the cost of service model include, without limitation

(a) the full labour, material, and other costs necessary to serve the new Customers less any contributions in aid of construction by the Customers or third parties, grants, tax credits, or non-financial factors offsetting the full costs that are deemed to be acceptable by the British Columbia Utilities Commission;

(b) the appropriate allocation of FortisBC Energy's overheads associated with the construction of the alternative energy extension;

(c) depreciation expense related to the capital equipment associated with the alternative energy extension; and

(d) the incremental operating and maintenance expenses necessary to serve the Customers.

In addition to the costs identified, the cost of service model will include applicable taxes and the appropriate return on investment as approved by the British Columbia Utilities Commission.

FortisBC Energy Utilities

FortisBC Energy Utilities
Background Information Related to Ownership and Regulatory Issues for TES

Prepared by:

EES Consulting

570 Kirkland Way, Suite 200
Kirkland, Washington 98033

A registered professional engineering corporation with offices in
Kirkland, WA; Bellingham, WA; and Portland, OR

Telephone: (425) 889-2700 Facsimile: (425) 889-2725

August 29, 2011

Mr. Paul Craig
Manager, Tariffs, Rate Design and Special Contracts
FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8

SUBJECT: Ownership and Regulatory Issues for TES

Dear Mr. Craig:

Please find attached our report for FortisBC Energy Utilities regarding Background Information Related to Ownership and Regulatory Issues for TES. This report addresses the appropriateness of offering multiple product classes within a regulated utility environment, the allocation of common costs among various product classes, and the protection of customers of the various product classes.

Very truly yours,

Gary S. Saleba

Gary S. Saleba
President

570 Kirkland Way, Suite 200
Kirkland, Washington 98033

Telephone: 425 889-2700 Facsimile: 425 889-2725

A registered professional engineering corporation with offices in
Kirkland, WA; Portland, OR; and Bellingham, WA

Contents

Introduction

FortisBC Energy Utilities (FEU) has proposed offering thermal energy system (TES) product to its customers in the near future. TES primarily includes district heating systems that provide steam produced directly from natural gas or through a cogeneration process where both power and steam are jointly produced. The FEU have approved tariff provisions to offer TES and we are advised that they have over 20 projects in development. Providing multiple products is a common practice for regulated utilities and there are benefits associated with the sharing of common expertise, operational efficiencies and sharing of overhead costs.

An inquiry has been opened before the Commission to address policy considerations associated with FEU providing this new product class within FEU. Specific concerns that have been expressed include the potential of cross-subsidies between the natural gas product class and TES and the appropriate regulatory oversight. In our opinion, there are numerous cases where regulated utilities with multiple products classes sufficiently manage these issues.

FEU requested EES Consulting to provide an opinion regarding the use of multiple product classes within a regulated utility based on its experience and research on comparable utilities. Specific issues that need to be addressed include the structure of different product classes, how common costs are allocated among the product classes, and what regulatory constructs are employed to protect customers of the different product classes. In addition, some background on district energy systems with respect to pricing and regulation is provided.

For clarification, this report uses the term product classes to refer to the separate natural gas and TES businesses. In some other cases these are also referred to as multiple classes of service, separate business lines, or different energy products. While this report is intended to discuss the natural gas and TES product within the FEU, it should be noted that the Fortis group of companies already have multiple product classes with natural gas provided by the FEU and electricity provided by FortisBC. Further, Fortis previously gained approval from the Commission to provide these multiple products in the Province when Fortis acquired Terasen Gas. Both of these products currently share certain overhead costs and both products are regulated by the Commission.

There are many cases where TES products, specifically district energy, are provided by regulated tariff. The primary difference for the TES products at FEU relative to other utilities that offer TES is that the FEU is proposing to create new districting heating systems rather than acquiring existing systems that have been in place for many years. In addition to those utilities offering TES products, many other cases exist where multiple product classes are offered by a single regulated utility. The next two sections provide background information and examples of utilities that provide TES products and utilities that offer other multiple product classes. The final section presents and summarizes specific findings related to the issues requested by the FEU.

Note that this report is intended to provide background information and utility expertise related to the topics at hand and do not provide a legal review as to the applicability of ownership or regulatory issues specific to this case.

Background on TES/District Energy Utilities

While TES is a new business line for FEU, district energy systems have long been established in many locations throughout the world. In Europe it is common for municipal district energy systems to serve entire communities. Throughout North America district energy systems are commonly seen in urban settings as well as at institutional settings, such as universities and hospitals. There are a variety of ownership models for these systems, ranging from for-profit private companies to fully regulated utilities. The proposal set forth by FEU is well within the existing range of business models.

Types of District Energy Utilities

District energy is available in other Canadian Provinces. Enmax operates a district heating system in Calgary, and is looking at building up to 12 energy centres around the city. The University of Alberta owns and operates a district energy system at its Edmonton campus. Downtown Montreal's district energy system serves over 16 million square feet and is jointly owned by Dalkia and Gaz Metro. Enwave, which started as a non-profit cooperative but is now a private for-profit company, provides thermal energy in downtown Toronto and Windsor. Each of these systems has a very different ownership model.

Because many district energy systems have been in place since the late 1800's and early 1900's, the situation differs from the new systems being proposed by FEU. This does not preclude similar treatment, however. There are many cases where district energy is a regulated utility service either on a stand-alone basis or within an existing electric/gas utility. The following are examples of district energy systems outside of B.C. that have regulated rate tariffs.

- Concord Steam Corporation (New Hampshire)
- Consolidated Edison Steam, New York
- NRG Energy Center Pittsburgh
- NRG Energy Center San Francisco
- NRG Energy Center Harrisburg
- Wisconsin Energy
- Public Service Company of Colorado (Xcel Energy) Steam
- Aurora Energy (Steam) – Alaska

Research related to district energy systems included examining the pricing in place for service. While the municipal and regulated utilities generally provided rate tariffs available to all customers, systems under private non-regulated ownership did not have generic rates available. In most of these cases, rates are negotiated on a case-by-case basis for each customer and are not publicly available.

The following partial list of service providers by ownership categories was provided by www.energy.rochester.edu. While this list is a little dated, it illustrates the broad range of options for businesses ownership of district energy systems.

District heating systems operated as part of an investor-owned utility. These are generally utilities that provide gas and/or electricity and are regulated by the appropriate state commission.

- Public Service Company of Colorado
- Consolidated Edison, New York
- Alabama Power Company
- Detroit Edison
- Wisconsin Electric Power Company
- Commonwealth Energy Steam Corp. Massachusetts
- Thermal Energies, Connecticut

District heating systems owned by private companies owning multiple systems. These are for-profit firms that do not operate other types of utilities. Rates may or may not be regulated by the state commission.

- Trigen Energy Corp
- Thermal Ventures
- Pacific Energy
- NRG Energy

District heating systems independently owned. These are for-profit entities that are formed to operate a single system.

- District Energy St. Paul, Minnesota
- Seattle Steam Corp., Washington
- Community Central Energy Corp, Pennsylvania
- Energy Systems, Co., Nebraska
- Metro Nashville District Energy System
- Enwave, Toronto

District heating systems municipally owned. These generally operate a single system and are owned and operated by the City in question. They are not regulated by state commissions but are subject to oversight through the public meetings of the municipal entity.

- Boise, Idaho
- San Bernardino, California

- Lansing, Michigan
- Buffalo, New York
- Virginia, Minnesota
- Eugene, Oregon
- Fairbanks, Alaska
- Holyoke, Massachusetts

Cooperatively-owned district heating systems. Cooperative systems are not-for-profit entities and are set up to include customer ownership of the facilities.

- Rochester District Heating Cooperative, New York
- Duluth Steam Cooperative Association, Minnesota
- Texas Steam Cooperative, Houston

Examples of Regulated Steam Utilities

Concord Steam

Concord Steam Corporation is a private corporation regulated by the New Hampshire Public Utilities Commission. It supplies steam to approximately 110 customers, including 200 commercial and institutional buildings, government agencies such as the City of Concord, the State of New Hampshire and federal offices. It also cogenerates electricity for its own use and for sale to utilities. In 2005, Concord proposed to join its nonregulated cogeneration division with the regulated steam operations. The PUC approved the merger. Previous to the merger, there was an approved allocation of costs between the regulated steam business and the non-regulated cogeneration business. The allocation was no longer necessary under the merged entity.

Consolidated Edison

Consolidated Edison is one of the largest utilities in the U.S., providing electric, gas and steam service in New York. The current company exists as a result of many mergers over time. Consolidated Edison operates the largest district-energy steam system in the United States. Consolidate Edison delivers electricity to more than three million customers through the world's largest system of underground electric cables. Natural Gas service is provided to over 1 million customers. Steam is provided to over 1,700 customers and accounts for about 6 percent of Con Edison's operating revenues.

Specific allocation percentages for common and expenses plant are in place to equitably share costs among the various business lines. The allocation has been approved through the regulatory process.

The steam utility provides overall benefits to utility customers due to reduced environmental emissions and improved energy efficiencies.

Approximately half of the supply to Con Edison's steam production comes from cogeneration units. Through the application of cogeneration, the release of approximately 1.5 million tons of CO_2 per year is avoided (equivalent to 274,500 cars), when compared to individual electric and steam production methods.

The use of Steam Service for heating eliminates the prospect of additional strains on the natural gas delivery infrastructure. Without the Steam System approximately 250 Mdt/day of additional gas load would be added to the Con Edison Gas System. This equates to $280 million per year savings to gas customers avoiding the increasing need of capital infrastructure investments. Steam air conditioning offsets peak load requirements on the electric supply and delivery infrastructure in critical electric networks, benefitting electric customers. There is approximately 580,000 ton of installed steam-driven A/C on the Steam System; if these tons of steam A/C were converted to electric, about 350 MW of additional electric load would be added to Con Edison's Electric System. The Company's analysis shows that steam service provides an annual savings of approximately $600 million per year to Electric Customers.

NRG Energy

NRG Energy owns and operates multiple utilities providing electric generation, electric distribution, and several district heating entities. NRG Thermal has several wholly owned subsidiaries, including NRG Energy Center Harrisburg, NRG Energy Center Pittsburgh and NRG Energy Center San Francisco.

NRG Energy Center Harrisburg is a public utility regulated by the Pennsylvania Public Utilities Commission. It provides district heating for buildings in a one-square-mile area of Harrisburg, Pennsylvania's, central business district. The Energy Center generates and distributes steam for use in space heating, domestic hot water heating, humidification and industrial processes. It serves approximately 200 downtown customers totaling 10 million square feet of space.

NRG Energy Center Pittsburgh supplies district heating and/or cooling services to buildings on the north side of Pittsburgh, Pa., in a service area anchored by the Carnegie Science Center, PNC Park and Allegheny General Hospital. Serving more than 30 customer buildings, the Energy Center provides both district heating and cooling services to a total of 6.3 million sq ft of building space. They produce and distribute steam used for heating, domestic hot water, humidification and sterilization; hot water for space heating and domestic use; and chilled water for air conditioning. The Energy Center is a public utility regulated by the Pennsylvania Public Utility Commission.

NRG Energy Center San Francisco supplies energy-efficient district heating services to buildings in a two-square-mile area of the central business district of San Francisco, California. At the Energy Center's two downtown plants, they produce steam and pipe it to approximately 170 customer buildings for space heating, domestic hot water, air conditioning and industrial process use. The Energy Center serves a total of more than 37 million square feet of space in San Francisco's commercial core.

Public Service Company of Colorado

PSCo is a wholly-owned subsidiary of Xcel Energy Inc. (Xcel), which provides electric energy to approximately 1.4 million retail customers and various Wholesale Customers. PSCo provides natural gas, electric and steam product classes in Colorado. The steam provides district heating and cooling in downtown Denver using steam produced at the Zuni cogeneration station.

Wisconsin Energy

Wisconsin Energy is the largest electric, natural gas and steam provider in Wisconsin. It serves over 1.1 million electric customers, over 1 million natural gas customers and 452 steam accounts. Wisconsin Energy Corporation is a diversified holding company. The Company operates primarily through two segments: a utility energy segment and a non-utility energy segment. The Company's utility energy segment consists of Wisconsin Electric and Wisconsin Gas, operating together under the trade name of We Energies. Its electric utility operation engages in the generation, distribution and sale of electric energy. Its non-utility energy segment derives its revenues primarily from the ownership of electric power generating facilities for long-term lease to Wisconsin Electric.

The natural gas utility operation is engaged in the purchase, distribution and sale of natural gas to retail customers and the transportation of customer-owned natural gas throughout Wisconsin. It also operates a steam utility that generates, distributes and sells steam supplied by two of its power plants.

Utilities with Multiple Regulated Product Classes

In addition to those regulated utilities that also provide district heating systems, there are numerous instances where utilities offer more than one regulated product class, the most common occurrence being utilities offering both electric and natural gas service. The existence of multiple products generally allows for cost efficiencies in the areas of management, engineering, billing and customer service. Where rates are set on a cost of service basis, these efficiencies tend to reduce costs for customers in the various product classes. Gas and electricity are substitutes for one another for certain end uses, such as space and water heating, and a utility offering both product classes can preserve customer choice. This is also the case between natural gas and the proposed TES products, with the proposed FEU model similarly preserving choice for its customers.

The efficiencies gained by offering multiple products can be seen through the many mergers that took place in the U.S. utility industry during the 1990's. Many of these were in reaction to expected changes in the electric industry and were completed to place the new utility in a better competitive position. This is not unlike the current situation of FEU, which has articulated a need to find a way to remain competitive given the environmental and regional policy issues facing the energy industry in B.C.

Many of the mergers combined electric and gas distribution utilities to take advantage of synergies in management, billing and metering, marketing, regulatory and operational functions. These types of mergers were termed "convergence" mergers, with over 20 taking place in the late 1990's. In all cases, these mergers required public interest approval by one or more state Utility Commissions and in many cases also required Federal approval.

While the merger cases are not identical to FEU's proposed introduction of TES, they do demonstrate that regulated utilities can successfully offer more than one energy product in an efficient manner without compromising competition in the industry. Duplicate functions can be avoided, expertise can be shared between the two business lines, methods for sharing costs can be put in place to avoid cross-subsidies between the product classes, and to ensure that rates properly reflect the cost of each service.

One of the issues that needed to be demonstrated in many of the cases was the ability for the Commission to maintain its regulatory authority over the functions of the utility. In the case of FEU, we are advised that the proposed TES business line would fall under the regulatory oversight of the Commission, which would provide a transparent pricing mechanism, would ensure all customers are treated equitably, would eliminate the potential for excessive profits and would alleviate concerns about anti-competitive practices through the appropriate allocation of costs. In our opinion, this is consistent with how utilities with multiple product classes generally operate and meets the requirements set out by numerous regulatory bodies for merging utilities and those that offer multiple products.

Specific Regulatory Issues

While the previous sections provided numerous descriptions of utilities that are both regulated and offer multiple product classes, this section presents and summarizes the findings specific to the issues in question. These issues include how the different classes are regulated, how common costs are shared among the product classes, and how customers within a particular product class are protected from issues flowing over from another product class.

Regulation of Utilities with Multiple Product Classes

Given the examples provided in previous section, there are numerous cases where steam/district heating is provided as a product class within another utility, with each product class being subject to regulatory oversight. There are many more examples with natural gas and electricity products both regulated on an individual basis. Utilities that offer multiple product classes are generally subject to regulatory approval for each product class individually.

The separate regulatory oversight for multiple product classes occurs regardless of the corporate structure. Commonwealth Energy has separate subsidiaries for gas, steam and electricity, and each is individually regulated. In the case of Puget Sound Energy, there is a single legal entity for gas and electricity, and rate cases are filed jointly. However, revenue requirements are distinct for each product class and a separate cost of service is used for gas and electricity. Con Edison also has a single subsidiary that provides natural gas, steam and electric services, with separate regulatory filings for each product class.

There are instances where companies offer certain regulated products and other products that are unregulated. This is particularly true in jurisdictions where a product has become unregulated. For example, in California San Diego Gas & Electric previously provided full service electricity that included generation, transmission and distribution service on a blended basis to the end user. When the electric market was deregulated, Sempra Energy became the parent company with SDG&E still providing electric transmission and distribution and Sempra Generation being a non-regulated provider of generation.

In the case of the TES products proposed by the FEU, it is our opinion that it is consistent with the regulatory practice elsewhere for the FEU to offer the products within a separate product class and that the product class should fall under the regulatory approval of the Commission.

Allocation of Common Costs Among Product Classes

Because of the numerous cases where multiple product classes are offered by regulated utilities, it is common practice to develop allocation methods to share common costs among the entities. This is also necessary when a company provides service in multiple states because each state has a separate regulatory body and rates are regulated by each individual state. While the methodology may be slightly different in each case, the regulatory body must approve the allocation of shared costs. By approving both the overall level of overhead costs and the allocation method, the regulatory body ensures that customers of each product class pay a just and reasonable portion of shared costs in addition to the direct costs of the utility.

Con Edison has fixed Common Allocation Factors to share costs between electric, gas and steam services. The factors for the steam business range from 2.5% to 6.0%, depending on the cost account. EXCEL Energy, the parent company of Public Service Company of Colorado, uses various factors in allocating common costs to its subsidiaries and their product classes. Allocations are based on customer counts, operating revenue, direct O&M costs, labor costs and gross plant.

In the case of the Fortis companies, there is a shared services agreement in place that allocates costs among the various utilities on the basis of number of customers, energy use and rate base. Because the TES product class does not yet have any of these factors in place, it cannot be included in the current agreement. However, the FEU has proposed an assigned share of $500,000 of shared service costs to the TES product, based on factors such as estimates of time and work effort. This appears to be a reasonable level given the order of magnitude of effort relative to an entity such as TGI Whistler, that we are advised receives a$260,000 assigned share based on the standard agreement.

The allocation of overhead costs is also a common issue within a product class with respect to the allocation of costs among customer classes with a cost of service study. In our experience, general plant and administrative and general costs (A&G), once assigned to a product class, are generally allocated to customer classes on the basis of labour ratios, all other rate base, all other expenses or some combination of those factors.

Because the allocation of common costs is a well studied issue in front of the Commission and within the industry in general, it can be readily managed through regulatory oversight without leading to cross-subsidies among product classes. As the TES business becomes operational, with known customers, sales and rate base amounts, it can participate in the current shared services agreement for a more definitive allocation of shared costs.

Protection of Customers in Each Product Class

Customers within each product class are protected through regulatory oversight in several different ways. Each product class has its own regulatory oversight with approval required for new capital projects, rate of return, rate base, revenue requirements, sales forecasts and rate design. At the corporate levels, the method for the sharing of common costs are generally approved by the regulatory body before the allocated share is included in the revenue requirements for each product class, as discussed above.

In approving capital projects, the regulatory body approves projects and costs for each product class separately. If a project is not approved for inclusion, it becomes a cost to the shareholder and cannot be shifted to another product class.

The rate of return is determined separately for each product class, subject to regulatory approval, and depends on the risks and other circumstances of that product class. This means that the natural gas is not penalized by the fact that the FEU is starting the TES product class. Similarly, the TES rate of return and business risk is not lessened by any guarantees from the natural gas or electric product classes. The TES might benefit through a proven management structure and expertise that carries over to the TES product class. However, that does not take anything away from the natural gas product class and therefore will not harm the natural gas customers.

Sales and revenue projections from each product class are also subject to regulatory approval on an individual basis, and in each case, revenues from each product class are tracked separately and cannot be used to offset the costs of any other product class.

Expense items are tracked under separate accounts that generally follow a standard system of accounts for each product class. Revenue requirements for each class include these expense items for each product class, and are subject to review of the regulatory body. Through the regulatory process various customers are involved as interveners in the regulatory process and serve as another layer of oversight in addition to the staff and Commissioners of the regulatory body. In addition to the accounting methods used, this oversight ensures that costs are assigned to the appropriate product class and that cross-subsidies between product classes do not occur. As with capital projects, any costs that are not approved for inclusion in rates, are the responsibility of the shareholder and are not shifted to another product class.

As rates are generally set to be equal to the approved revenue requirements, rates for one product cannot be set to include any of the costs that belong to another product class.

In all cases, the burden of proof is with the utility to provide evidence that the capital projects, forecasts, revenues and costs are appropriate and for the benefit of the customers in question. There is supporting documentation that accompanies the various applications submitted to for approval by a regulatory body.

In our opinion regulated utilities with multiple product classes see sufficient regulatory oversight to ensure that there is not cross-subsidization between the various product classes, thereby protecting the customers in each product class.

PROFESSIONAL EXPERIENCE AND BACKGROUND OF

GARY S. SALEBA

EDUCATION

MBA, Finance
Butler University
Indianapolis, Indiana

BA, Economics and Mathematics
Franklin College
Franklin, Indiana

EMPLOYMENT

October 1978 to Present	EES Consulting, Inc. 570 Kirkland Way, Suite 200 Kirkland, Washington 98033 Registered Professional Engineering and Management Consulting Firm
Position:	President
Responsibilities:	Overall supervision and quality control responsibilities for all of EES Consulting's electric, water, wastewater and natural gas engagements in the areas of strategic planning, financial analysis, cost of service, valuations, mergers and acquisitions, rate design, load forecasting, load research, management evaluation studies, bond financing, integrated resource planning and overall utility operations. Overall responsibility for firm's offices in Kirkland, Portland, Bellingham and southern California.
Activities:	Numerous testimony presentations before regulatory bodies on utility economics, strategic planning, finance and utility operations. Supervised several integrated resource planning studies, average embedded and marginal cost of service studies, technical assessments and financial planning studies for electric, water, gas and wastewater utility clients. Participated in comprehensive resource acquisition, strategic planning and demand side management analyses. Developed and verified interclass usage data. Conceptualized and implemented compliance programs for the Public Utility Regulatory Policies Act and the Energy Policy Act of 1992. Contract negotiation and energy conservation assessments. Presentation of management audit, forecasting, cost of service, integrated resource planning, financial management, and rate design seminars for the American Public Power Association, Electricity Distributors Association of Ontario, American Water Works Association, and Northwest Public Power Association. Past Board

	member of Northwest Public Power Association and ENERconnect, Ltd. Past Chairman of Financial Management Committee and Management Division of the American Water Works Association. Project manager for construction of 248 MW gas turbine, and acquisition of over $500 million of utility service territory and equipment. Supervised engineer's report for over $5 billion in revenue bonds.
October 1977 to October 1978	National Management Consulting Firm
Position:	Supervising Economist
Responsibilities:	Analyzed various energy related topics to determine economic impacts. Reviewed utility financial activities.
Activities:	Participated in several utility rate/financial regulatory proceedings. Provided clients with critique of issues, position papers and expert testimony on the topics of cost of service, rate design, utility finance, automatic adjustment factors, sales perspectives and class load characteristics. Conceptualized load forecasting models and assisted in economic and environmental impact analyses.
June 1972 to October 1977	Indianapolis Power & Light Company P.O. Box 1595 B Indianapolis, Indiana 46206 Investor-owned Utility
Position:	Economist, Department of Rates and Regulatory Affairs
Responsibilities:	Provided general economic and rate expertise in Rates, Regulatory Affairs, Customer Service and Engineering Design Departments.
Activities:	Calculated retail and wholesale electric and steam class revenue requirements and rates. Prepared expert testimony and exhibits for state and federal agencies regarding rate design theory, application of rates and revenues generated from rates. Determined long range revenue and peak demand projections. Supervised comprehensive load research program. Supported thermal plant Environmental Impact Statements. Provided industrial liaison.

PARTIAL LIST OF CLIENTS FOR WHOM FINANCIAL, OPERATIONAL, STRATEGIC PLANNING AND ALLOCATIONAL/RATE ANALYSES PROJECTS HAVE BEEN PERFORMED BY GARY S. SALEBA

UNITED STATES OF AMERICA

Alabama

City of Birmingham Water and Wastewater

Alaska

City of Barrow
City of Wrangell
*Alaska Public Service Commission
*Municipal Light and Power
Alaska Village Electric Cooperative

Arizona

*Tucson Electric Power
City of Dodge
City of Page
Navopache Electric Cooperative

Arkansas

City of North Little Rock

California

City of Indian Wells
City of Palm Desert
City of Moreno Valley
*City of Corona
City of Redding
*Sacramento Municipal Utilities Board
City of Burbank
*State of California - Department of Water Resources
*Turlock Irrigation District
*City of Palo Alto
City of Anaheim
El Dorado Irrigation District
City of Glendale
*City of Pasadena
City of Roseville
Yucaipa Valley Water District
*Los Angeles Department of Water and Power
Nor–Cal Electric Authority
Jefferson JPA
City of San Marcos

California (cont'd)

City of Cerritos
Coachella Valley Association of Governments
California Power Authority
Santa Clara Valley Water District

Colorado

*CFI Steel
*Moon Lake Electric Association
City of Denver - Wastewater
*Denver Water Board

Connecticut

City of Groton

Florida

City of Pompano Beach
Florida Public Service Commission
Dade County Water and Wastewater Utilities

Idaho

Kootenai Electric
*Northern Lights
Salmon River Cooperative
Prairie Power and Light
*Department of Energy
City of Moscow
Fall River Cooperative
Lower Valley Power & Light
*Industrial Customers of Idaho Power
Clearwater Power & Light
City of Heyburn

Illinois

*City of Highland
City of Collinsville
City of Peru
City of Winnetka

Indiana

*Indianapolis Power & Light Company

<u>Iowa</u>

*City of Iowa City

<u>Kentucky</u>

*Kentucky-American Water Company

<u>Minnesota</u>

Polk-Burnett Electric Coop

<u>Missouri</u>

*General Motor, Inc.

<u>Montana</u>

PPL Montana
Montana Associated Cooperatives
Sun River Electric Cooperative
*Montana Power Company
Colstrip Community Center
Flathead Electric Cooperative
Glacier Electric Cooperative
Vigilante Electric Cooperative
Montana Electric Cooperative Association
Western Montana G&T
Northwestern Energy, Inc.
Yellowstone Valley Electric Cooperative

<u>North Dakota</u>

City of Watford City
Garrison Diversion Conservancy District

<u>Oregon</u>

*Emerald PUD
Clackamas Water District
Central Lincoln PUD
*Springfield Utility Board
Tri-Cities Service District
City of Portland
City of Gladstone
City of West Linn
City of Oregon City
*Public Power Council
Central Electric Cooperative
Warm Springs Energy Cooperative
Northern Wasco PUD
West Oregon Cooperative

South Dakota

Black Hills Electric Cooperative

Texas

City of League City
City of Brownsville
*City of Lubbock
Pedernales Electric Cooperative
City of San Antonio
*Texas Municipal Power Agency

Utah

*Moon Lake Electric Association
Utah Association of Municipal Power Systems

Washington

*Western Public Agencies Group
TrendWest Resorts
Weyerhaeuser Corporation
Costco
*Pend Oreille County PUD
City of Richland
Industrial Customers of Grant County
*Benton REA
Seattle City Light
*Clark Public Utilities
City of Blaine
*Snohomish County PUD
*City of Port Angeles
*Clallam County PUD
Chelan County PUD
*City of Tacoma Electric, Water and Rail Utilities
*Mason County PUD No. 3
*Peninsula Light Company
Washington Utilities and Transportation Commission
*Grays Harbor County PUD
*Pacific County PUD
City of Gig Harbor
Ferry County PUD
*City of Ellensburg
City of Redmond
Grant County PUD
*Klickitat County PUD
Cascade Natural Gas
*Building Owner's Management Association
City of Kennewick
Daishowa Corporation
Seattle Water Department

Washington (cont'd)

City of Bellingham
*US Ecology, Inc.
*Avista Corporation
*Cowlitz County PUD
*City of Cheney
*City of Yakima
City of Bellevue
City of Shoreline
Douglas County PUD
AT&T
WorldCom
City of Toppenish
City of Shoreline

Wisconsin

*Wisconsin Manufacturing Association
Polk-Burnett Cooperative

Wyoming

*Lower Valley Power and Light

CANADA

Alberta

*University of Alberta
*City of Lethbridge
*City of Red Deer
City of Medicine Hat
Ocelot Chemicals
Aqualta
City of Calgary—Water and Wastewater Utilities

British Columbia

*Fortis, BC
Alcan, Ltd.
*Princeton Power & Light
*West Kootenay Power
*Ministry of Fisheries
Crows Nest Resources
Highland Valley Cooperative
*Council of Forest Industries
Crestbrook Industries
Royal Oak Mines
UtiliCorp Canada
*Joint Industrial Electric Steering Committee
*British Columbia Transmission Corporation
*Terasen Gas

Manitoba

*Manitoba Legal Aid

Northwest Territories

*Northwest Territories Power Corporation

Ontario

ENERconnect, Inc.
Ontario Hydro
*Municipal Electric Association
North York Hydro
Toronto Hydro
*Ottawa Hydro
Electricity Distributors Association
Ontario Energy Board
*Association of Major Power Companies (AMPCO)

OTHERS

American Public Power Association
American Water Works Association
California Municipal Utilities Association
Northwest Public Power Association

*Prepared Expert Testimony

Appendix G

Energy Efficiency and Conservation

1. 2008 Long Term Resource Plan Excerpts
2. 2010 Long Term Resource Plan Excerpts
3. 2008 EEC Application Excerpts
4. 2010 EEC Report Excerpts
5. 2012-2013 FEI RRA Excerpts
6. Expert Evidence of Habart and Associates Regarding Incentives

4 ENERGY EFFICIENCY AND CONSERVATION

EEC programs are the main focus of DSM activities. DSM refers to "utility activity that modifies or influences the way in which customers utilize energy services." TGI has been offering DSM programs since 1997 to its customers, focused on energy efficiency and conservation activity, while TGVI has had a marketing budget allocated for customer additions and efficient load building since the company was acquired from Centra Gas in 2002.

EEC programs have long been important to Terasen Gas in helping to meet customer needs and ensure the wise and efficient use of energy in B.C. A Conservation Potential Review ("CPR") undertaken for Terasen Gas in 2005 and received in 2006 identified substantial additional savings that could be realized beyond the programs existing at that time. The CPR was discussed in some detail in the 2006 Resource Plans. Additionally, climate change concerns, rising energy costs for all types of energy and the scale of expected growth in energy demand has raised the importance of EEC programming for utilities across North America. In B.C., the *UCA Act* became law on May 1st, 2008 and sets out the requirement for utilities to complete DSM plans which are to be included as part of the utility's Resource Plan.

Terasen Gas formally submitted its latest DSM plan to the BCUC on May 28, 2008 in the form of an application to expand EEC programming for residential and commercial rate classes across both TGI and TGVI service territories. This chapter of the Resource Plan provides an overview of past and present EEC programming at Terasen Gas and the background behind the new EEC plan, including a comparative assessment of DSM programming at other gas and electric utilities in the region. The plan submitted to the BCUC is then summarized. The expected impact on the forecast of demand for natural gas is discussed in the final section of this Chapter as well as in Chapter 3.

4.1 Past and Current EEC Programs

Terasen Gas has enjoyed some significant successes within the existing budget and programming. For example, through DSM programming from 2000 to 2007, TGI customers have saved approximately $14 million in cumulative annual energy costs and have reduced consumption by 1,270 TJ. Those cumulative savings will persist, year over year, for as long as the measures that were installed as a result of DSM programming during the 2000 to 2007 time frame remain in place. The current DSM budget is part of the Terasen Gas negotiated settlement and as such, has not changed since 1997. Table 4-1 represents current DSM Investment by Terasen Gas.

Table 4-1 Terasen Gas Funding for DSM Programs

Utility and Service Territory	Program amount	Incentive and rebate amount
Terasen Gas Inc. Lower Mainland and Interior B.C.	$1.624 million	$1.5 million
Terasen Gas Vancouver Island	$500, 000	$650,000
Totals	$2.12 million	$2.15 million

Excellence in Efficiency

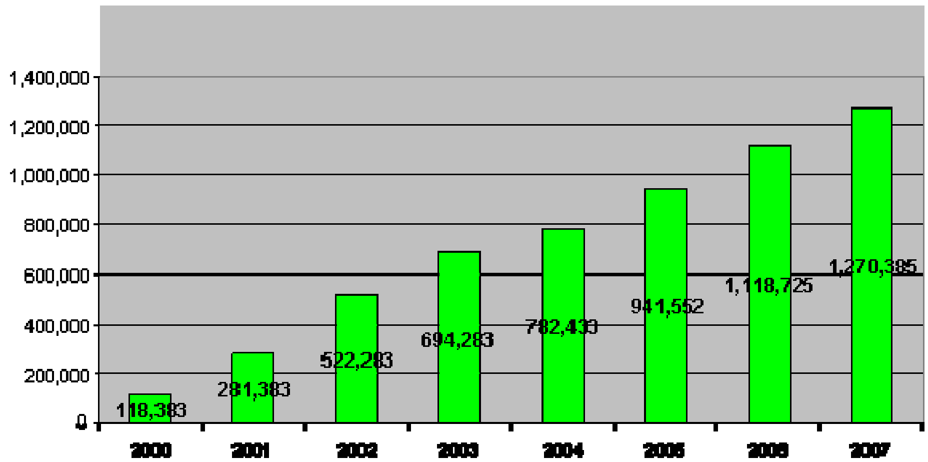
Terasen Gas has been recognized for the success of historical DSM programs. In 2006, the Companies were honoured to receive Natural Resources Canada's Energy Star Award for Campaign of the Year.

And in 2008, Terasen was very proud to be included in the Ministry of Energy, Mines and Petroleum Resources "Energy Efficiency and Community Solutions Team", a finalist for the Premier's Award Promoting Innovation and Excellence.

TGI

Over the past eight years, TGI has helped its customers reduce energy usage by over 1,270 TJ and associated greenhouse gas emissions by approximately 64,000 tonnes through the current DSM budget and programming. These numbers only represent savings from incentive and assessment programs as well as the Destination Conservation Program. Savings that result from education and outreach programs such as Terasen Gas' Hot Tips (for example: weather-stripping, replacing a leaky faucet or installing an aerator on water taps) are in addition to the reported savings. Figure 4-1 shows the TGI energy savings on a cumulative basis since 2000.

Figure 4-1 TGI Cumulative Gas Savings from DSM Expenditure (GJ)



TGVI

The changes in energy usage identified in Figure 4-1 do not include those associated with TGVI. TGVI's DSM approach has historically been focused on marketing and efficient load building since natural gas has only been available on Vancouver Island since 1990. The relative newness of natural gas appliances on TGVI means that opportunities to upgrade existing gas appliances to more efficient versions have been limited. DSM activity for TGVI has historically encouraged conversion of non-gas customers to gas customers, as well as the installation of natural gas equipment in new construction.

A description of all current and past DSM programs implemented by TGI and TGVI along with a summary of the energy savings achieved during the most recent three year period of programming is included in Appendix I. The current level of DSM programming is considered within the reference case of Terasen Gas' demand forecast, since the impact on customer additions and use per customer are recalculated annually as described in Chapter 3.

TGW

TGW has not historically offered defined DSM programs to its customers but has undertaken or participated in a number of initiatives related to energy efficiency. The Whistler Demand Side Management Study commissioned in 2003 led to follow up energy use assessments for select medium and large commercial customers to provide both the Utility and the customer with a better understanding of their energy consumption. Destination Conservation, a school energy efficiency and awareness program delivered to students and administration was offered to the local school board.

TGW also participated in the RMOW's Sustainable Community Plan, helping to develop Whistler's Sustainable Energy Plan. The Sustainable energy Plan views natural gas as an important bridging fuel for the development of new and alternative energy technologies and practices in Whistler that will ultimately reduce the community's carbon footprint. The Sustainable Energy Plan was an important part of the TGVI and TGW application to BCUC to extend natural gas service to the community and convert TGWs customers' fuel from Propane to Natural Gas. With construction of the project underway, the implementation of alternative energy solutions supported by natural gas infrastructure, the immediate carbon intensity reduction that natural gas offers over propane and simply a better general awareness of Whistler specific energy issues that will result, provide the best energy efficiency and conservation effort that TGW could offer at this time. For the future, TGW is collaborating with RMOW on the development of a DSM initiative based on the results the appliance conversion audit.

4.2 Need for Expanded Energy Efficiency and Conservation Programming

A number of factors have led Terasen Gas to apply for expanded EEC programming and provide a context for the types of programs and amount of funding requested. These factors include recent Provincial policy and legislative changes, a comparative analysis of EEC programming in other jurisdictions and the findings of the 2006 Terasen Gas CPR and market changes that impact those findings as well as Terasen Gas' ongoing effort to help customers manage their energy costs. Terasen Gas has also reviewed BC Hydro's most recent CPR and Residential End Use Study ("REUS") to identify and account for differences in the findings or assumptions of these two utilities, which share much of the same service territories.

4.2.1 Provincial Energy Policy and Legislation

Over the last year, rapid changes in public policy initiatives (both provincial and federal) are placing a high level of importance on environmental and energy use issues. The 2002 B.C. Energy Plan was primarily focused on secure, reliable, low cost supply and environmental responsibility as it related to resource development. The 2007 Energy Plan, however, emphasizes the development of B.C.'s natural gas resources, the importance of electricity conservation, electricity self-sufficiency and the need for utilities to pursue all cost effective DSM.

Among the developing legislation or legislative amendments resulting from the Energy Plan are The Greenhouse Gas Reductions Target Act, The UCA Act, Bill 27 (The Green Communities Act), Bill 37 (The Carbon Tax Act) and proposed Building Code amendments that will establish the Province's Green Building Code. Each of these new and proposed legislative changes, as discussed in Chapter 2, are aimed at improving energy efficiency and emissions reductions. Terasen Gas' 2008 EEC application reflects the emphasis government and consumers have put on environmental issues and aims to provide the resources to help consumers reduce energy intensity and support government policy.

Increasing energy prices has also led to increased public awareness and interest in energy saving measures to help reduce residential and commercial energy bills. The Carbon Tax Act is slated to go into effect in July 2008, making all fossil fuel based energy sources subject to a carbon tax that is intended to drive consumers towards more energy efficient and less carbon intensive choices. In the case of natural gas, end users will pay $0.50 per GJ beginning June 2008, rising in $0.25 annual increments until reaching $1.50 per GJ in 2012. Natural gas has the lowest carbon intensity (as described in Chapter 2) and lowest pollution emissions of any fossil fuel and as such, continues to play a major role in helping the province and the Region reach carbon reduction targets.

4.2.2 Review of DSM Programs at Other Utilities

As part of the research for its 2008 EEC Application, and to understand the level of DSM expenditure, types of programs offered and scope of activity at other utilities, Terasen Gas conducted a review of DSM programming in B.C. and other jurisdictions. The study reviewed and evaluated energy efficiency and conservation programs offered by other North American utilities. Background research was collected via the internet from utility, public, government and commission web sites. Initial findings were then followed by personal telephone interviews with key staff responsible for DSM activities at these utilities. Table 4-2 summarizes key findings and clearly shows that the current Terasen Gas EEC expenditure levels are significantly lower than those of other major North American utilities.

Table 4-2 DSM Activity Summary – Other Utilities

Company Name	Utility Type	2007 DSM Annual Budget ($ in millions)	DSM Funding Treatment	Customer Base	2006 Total Revenues ($ in millions)	% Spent on DSM of Revenue	DSM Spend per customer	2006 Annual Sales Volume
Pacific Gas and Electric Company ("PG&E")	Combined	279.0 [1]	Public Purpose Fund	4,200,000 [5]	12,530	2.23%	$66.43	425.9
Manitoba Hydro	Combined	9.0	DSM costs are treated as capital and amortized over a fixed time period.	258,000	517	1.74%	$34.88	147.6 [7]
Southern California Gas Company ("SoCal Gas")	Natural Gas	56.6 [2]	Public Purpose Fund	5,600,000	4,180	1.35%	$10.11	946.0
BC Hydro and Power Authority ("BC Hydro")	Electric	52.3 [3]	DSM costs are treated as capital and amortized over a fixed time period.	1,704,671	4,311	1.21%	$30.68	190.5
FortisBC	Electric	2.5	DSM costs are treated as capital and amortized over a fixed time period.	154,000	208	1.19%	$16.06	11.1
Northwest Natural Gas Company ("NW Natural")	Natural Gas	11.0 [4]	Public Purpose Fund	636,000	1,000	1.10%	$17.30	125.8
Union Gas	Natural Gas	17.0	DSM costs are recovered through rate base	1,300,000	2,100	0.81%	$13.08	1,303.0 [8]
Enbridge Gas Distribution ("Enbridge")	Natural Gas	22.0	DSM costs are recovered through rate base	1,800,000	3,016	0.73%	$12.22	445.0
Gaz Metro Limited Partnership ("Gaz Metro")	Natural Gas	8.8	as O&M	167,000	2,000	0.44%	$52.69	271.8
The Terasen Utilities	Natural Gas	4.3	Program costs as O&M; program incentives are amortized over fixed time period	911,935	1,635 [6]	0.26%	$4.69	208.0 [9]
Puget Sound Energy ("PSE")	Combined	6.1	DSM costs are recovered via a rider on customer bill	718,000	2,905	0.21%	$8.52	205.1
SaskEnergy	Natural Gas	1.6	as O&M	325,000	1,254	0.13%	$4.92	125.0
ACTO Gas	Natural Gas	Part of marketing budget	as O&M	969,200	2,890	n/a	n/a	219.0

Comments:

1 This figure reflects the 2007 DSM budget for electrical and gas initiatives. This covers labor, rebates and advertising. An additional $24 million will be spent on research and evaluation. On average, 86 per cent of funds are related to the electric side

2 This figure is comprised of the following components: $4.9 million (operating costs) and $47.3 million in deferred capital - note that it is an actual figure rather than a budget figure.

3 This figure reflects the 2007 DSM budget which covers labor, rebates and advertising. An additional $4.3 million will be spend on research and evaluation.

4 This figure is the sum of $9 million that is dedicated for DSM and market transformation programs implemented through the Energy Trust of Oregon (ETO) and $2 million for low income weatherization administrated by NW Natural.

5 This figure refers to Natural Gas customers only at PG&E.

6 These are combined revenues for Terasen Gas Inc. and Terasen Gas Vancouver Island

7 Includes sales for residential, commercial and industrial sectors (53PJ) and transportation services (23PJ)

8 This number is comprised of 509 PJ for distribution and 794 PJ for transporation.

9 This includes the total volume numbers for TGVI (including ICLP/Hydro; VIGJV-Inland & Squamish Gas) and TGI.

4.2.3 Terasen Gas Conservation Potential Review

Terasen Gas' current CPR was completed in 2006. The study was designed to analyze the amount of EEC potential in different geographical areas in the TGI and TGVI service territories. The study parameters were based on BC Hydro's 2002 Conservation Potential Review, with one notable exception: the Terasen Gas CPR included an analysis of fuel-switching opportunities. As discussed in Chapter 2, Terasen Gas believes that fuel-switching from electric to natural gas space and water heating in homes and businesses should be an important part of helping B.C. to achieve electricity self sufficiency targets and reducing carbon emissions throughout the PNW.

As discussed in the 2006 TGI Resource Plan, the CPR was commissioned with the intent to file an application for increased EEC activity with the BCUC. The 2006 Resource Plan outlined Terasen Gas' preliminary, high-level understanding of the outcomes of the CPR, as well as recommendations for further EEC planning. Further work on converting the CPR results to EEC program development commenced in the fall of 2006, following the submission of TGI and for TGVI Resource Plans.

Among other things, the CPR and subsequent analysis demonstrated the following key findings:

- Since the last time funding levels were reviewed, there has been a significant change in the market place. Energy prices have increased substantially over the last ten years and there is an increased focus on reducing end user consumption and energy costs. Additionally, there is increased customer and societal desire for finding innovative ways to increase energy efficiency.
- Government policy and direction have responded to public interest concerns and energy utilities are being encouraged and directed to invest more resources into energy efficiency and conservation activities in order to meet public objectives.
- The current levels of funding are inadequate. TGI's current funding levels were established over ten years ago. TGVI funding has also not been altered for many years. Funding for Terasen Gas is substantially lower than that of other utilities.

Terasen Gas believes that the CPR, and subsequent analysis, demonstrates a need to expand cost-effective EEC programs.

4.2.4 BC Hydro CPR Results on Fuel Switching Opportunities

In 2007, BC Hydro contracted Marbek Resource Consultants to undertake a comprehensive technical review, and develop a 2007 CPRfor BC Hydro's service territory. The 2007 BC Hydro CPR built on previous studies to help assess electricity conservation opportunities in B.C. The 2007 CPR identified almost 20,000 GWh/yr of economically feasible energy savings by the year 2020. However, a series of workshops determined that approximately 50% of the economically viable potential is realistically achievable when taking customer behaviour into account. The findings from the 2007 BC Hydro CPR support the 2007 B.C. Energy Plan target of 10,000 GWh/yr savings through conservation by 2020 (50% of BC Hydro's incremental resource needs).

The BC Hydro CPR also included an examination of potential electric savings from electricity to natural gas fuel-switching in certain applications. The total identified electric energy savings from fuel-switching measures that passed the economic screen was between 6,671 GWh/yr and 3,291 GWh/yr in 2026, respectively, under the 2007 CPR current and high natural gas supply cost forecasts.

Although the 2007 CPR found significant Economic Fuel Switching Potential available to BC Hydro, it used current customer rates in its analysis to determine that there is no Achievable Potential for BC Hydro's DSM group, PowerSmart, to actively engage in Fuel Switching programs. This conclusion was based on an assessment that natural gas measures either have excessively long payback periods or cost customers more to install and in some cases marginally more to operate compared to electricity. This contradictory result (Significant Economic Potential vs. Zero Achievable Potential) arises because the retail rates for electricity are lower than BC Hydro's cost of incremental supply.

The Terasen Gas CPR and EEC application disagree with this BC Hydro finding. Electrical rates are on the rise as a result of BC Hydro's need to acquire substantial expensive new generation resources to meet the Provincial electricity self-sufficiency and renewable generation targets. Terasen Gas believes that to reflect the true cost of supplying incremental electricity demand, the analysis of achievable fuel switching potential should include the incremental costs rather than incorporating heritage costs of electricity. This treatment of costs will also perform better in sending consumers the proper price signals, thereby better promoting energy conservation and use of the right fuel for the right application.

Terasen Gas proposes to support fuel switching through its EEC application and believes that electricity customers should be encouraged to participate in helping achieve the economic potential of electricity conservation offered by fuel switching programs. Education and incentives are one mechanism for this encouragement as are the use of connection policies and rates.

4.3 2008 Energy Efficiency and Conservation Application

Through its CPR and subsequent work, Terasen Gas identified numerous areas where our customers could participate in programs designed to lower energy consumption, and therefore their energy bills, if the additional funding for these programs is approved. As such, Terasen Gas has applied to the BCUC for increased EEC funding over a three-year time frame (2008-2010). The overall program expenditures over the three year time frame will equate to $56.6 million. This increased funding will result in a total DSM Investment per customer of $18.45 in the first year, growing to $23.02 in the third year. EEC Investment as a percentage of Gross Revenue will increase to 1.3% by the third year. The Executive Summary to the EEC application is provided in Appendix H.

Terasen Gas filed its Energy Efficiency and Conservation (EEC) application in May 2008. The objectives of the EEC application are to obtain the funding required to provide customers a higher level of efficiency and conservation services and to support government policy while ensuring that shareholders are able to achieve appropriate returns for providing these services.

The EEC application is expected to provide the following:

- Customer access to a wider variety of EEC incentive programs, assisting them to reduce energy consumption, lower their energy bills and reduce the individual and societal impacts associated with energy use.
- Harmonize TGI and TGVI EEC activities.
- Provide education for customers and the public at large about energy and conservation issues, leading to customers making more informed choices about energy equipment and actions and to support the creation of a "culture of conservation" in B.C.
- Maintain a competitive cost for end uses of natural gas, thus maintaining energy diversity in the province.
- Support BC Hydro and FortisBC in achieving their conservation goals, thus helping to minimize the need for all customers of the electric utilities to invest in additional generation and transmission infrastructure.
- Recognize the continued value in adding efficient cost-effective customers to the Terasen Gas distribution systems, keeping the use of natural gas and other energy forms competitive for all customers.
- Encourage the utilization of new and alternative technologies that have not to date enjoyed strong market penetration in British Columbia.
- Support the development and training of skilled trades' people who are fluent in the merits of conservation and efficient technology.
- An increase in allowed spending currently set at $4.274 million annually for TGI and TGVI combined, as shown in Table 4-3.

Table 4-3 TGI & TGVI Proposal for Energy Efficiency and Conservation Activity

Proposed ($million)

Utility	2008	2009	2010	Total by Utility
TGI	$13.996	$15.752	$17.196	$46.944
TGVI	$2.830	$3.043	$3.793	$9.666
Total	$16.826	$18.795	$20.989	$56.610

Incremental to Existing ($million)

Utility	2008	2009	2010	Total by Utility
TGI	$10.872	$12.628	$17.196	$40.696
TGVI	$1.680	$1.893	$3.793	$7.366
Total	$12.552	$14.521	$20.989	$48.062

- A change in financial treatment for Energy Efficiency and Conservation expenditures, treating the full expenditure as equivalent to capital, earning the regulated rate of return, and amortizing costs over twenty years following the year in which the cost was incurred.

This increase in funding supports B.C. Energy Policy Action No. 3, which states that utilities are to pursue all cost-effective DSM opportunities. Terasen Gas believes that the budget amount outlined above reflects all the cost-effective DSM opportunities available to it at this time.
This application is the first major initiative for Terasen Gas in response to the CPR and the 2007 Energy Plan. The evolving energy planning landscape, including the Provincial Government's new energy policies and carbon related legislation, is changing the way B.C. utilities plan demand side programming. Terasen Gas will continue to monitor developments in EEC programming across B.C. and the PNW to identify further opportunities beyond the current application to intensify EEC activities in accordance with Provincial directives.

4.4 Proposed CPR Update

Terasen Gas plans to commission an updated Conservation Potential Review (CPR) Study in 2009, to be received in 2010. The updated CPR will reflect new public policy, the changing energy landscape, and would form the basis of an application to the BCUC for the next stage of EEC funding for the period 2011 to 2014. This study and additional programming will be discussed further in the 2010 Terasen Gas Resource Plan.

4.5 Conclusion – EEC Impact on Demand

The expected impact of the proposed new EEC programs on TGI and TGVI demand has already been captured in the demand discussion in Chapter 3. In particular, Section 3.4.2 explains that EEC programs are expected to have an impact on overall annual demand for natural gas. The effect of those efficiency programs that reduce overall demand is to pull the demand forecast curve down from the reference demand forecast toward the low demand scenario. However, a number of efficiency programs build natural gas load while replacing less efficient or more carbon intensive load served by other fuels. These programs will result in a shift from the reference forecast toward the high demand scenario presented in Chapter 3.

While efficiency improvements that affect annual demand are in the best interest of customers and will help to reduce carbon emissions overall, these programs typically have minimal impact on the amount of gas used during the coldest days expected, since even the most efficient natural gas heating equipment is typically working its hardest during these peak demand events. Terasen Gas has found that these programs typically can delay capacity related infrastructure projects by zero years to up to just a few years. A review of the expected impact of EEC programs on infrastructure requirements for each of the Terasen Gas service areas is presented in Chapter 5.

5 ENERGY EFFICIENCY AND CONSERVATION – DEMAND SIDE RESOURCES

5.1 The Purpose and Benefits of Energy Efficiency and Conservation

EEC programs are an integral part of the Terasen Utilities' drive to meet British Columbia's current and future energy needs and ensure the efficient use of natural gas in its service territories. Implementing EEC helps to lower energy demand, ensure the right fuel for the right use, optimize the use of and cost for energy infrastructure and reduce the carbon footprint for all our customers. Since 1992, we have been operating EEC programs and initiatives which provide incentives and support customers in reducing their consumption of natural gas. Going forward, it is important for the Utilities to secure ongoing funding to provide consistent programs to the market and thereby maximize the benefits of EEC initiatives. While the Utilities' EEC activities align with the B.C. Government's recent energy and climate actions, we believe that the current cost-benefit criteria for some programs are outdated and limit the benefits that can be delivered for emission reductions and for certain customer groups such as low income earners. Recent energy policy and legislation (see Section 2) places a high level of awareness and importance on environmental and energy use issues.

Changing building codes and equipment standards have also led to increased public awareness and interest in energy saving measures. The Terasen Utilities are committed to providing the resources to help consumers reduce energy consumption through cost effective conservation programs. This section describes our current EEC activities, and outlines a future for long-term, sustained EEC activity.

Residential Energy and Efficiency Works – REnEW

(February and March 2010)

Funded by:	Terasen Gas, FortisBC, and BC Hydro
Developed by:	John Howard Society and Vancouver ACCESS BladeRunners
Targeting:	Individuals who are overcoming employment barriers because of life challenges such as mental health issues, a history of substance abuse, poverty or homelessness
Duration:	Four weeks intensive training
Location:	Kelowna and Vancouver

Left to right:
Jan Marston (VP, Customer Care, Human Resources & Operations Governance – Terasen Gas), REnEW program participant, and John Webster (CEO and President of ACCESS)

5.2 An Overview of EEC Funding

One of the items in the 2008 RP Action Plan was to "*implement the new EEC programs and continue research and planning for future EEC programming".* The 2008 Resource Plan provided an overview of the EEC application that was submitted to the BCUC in May 2008, requesting $56.6 million over three years for EEC activities. On April 16, 2009, the Commission released its decision and Order No. G-36-09 (the "EEC Decision"), which approved funding in aggregate of $41.5 million ($34.4 million for TGI and $7.1 million for TGVI) for EEC activities to the end of 2010.

In June 2009, TGI and TGVI filed their 2010-2011 Revenue Requirements Applications, requesting the following approvals:

- An increase in EEC funding to add programs for Interruptible Industrial customers (TGI only) and Innovative Technologies.
- Reallocation of funding to Affordable Housing initiatives.
- Additional funding to implement programs until the end of 2011 and an extension of the funding approved by the Commission in the EEC Decision of April 2009.

The Commission approved the TGI and TGVI Negotiated Settlement Agreement[106], which brought the total funding for EEC activities to $72.3 million for both service territories in 2010 and 2011, as can be seen in Table 5-1. In their 2009 EEC Annual Report, the Utilities reviewed 2009 EEC activities, and outlined an action plan for 2010[107]. Results of this review showed that 2009's activity was cost-effective with a portfolio-level Total Resource ratio of 1.2, providing value to customers and British Columbia's energy system.

Table 5-1: Total Approved EEC Funding 2010-2011

($000s)	TGI		TGVI	
	2010	**2011**	**2010**	**2011**
Residential and Commercial Programs	23,075	23,075	4,726	4,726
Affordable Housing	2,400	2,400	600	600
Industrial Interruptible	435	1,875	-	-
Innovative Technologies	2,300	4,669	478	956
Total	**28,210**	**32,019**	**5,804**	**6,282**

EEC activities align with customer, utility and government interests, while helping to protect the environment and stimulate B.C.'s green economy. Utilities such as the Terasen Utilities are a

[106] BCUC Order Numbers G-141-09 for TGI and G-140-09 for TGVI
[107] Energy Efficiency and Conservation Programs, 2009 Annual Report: http://www.terasengas.com/_AboutUs/RatesAndRegulatory/BCUCSubmissions/default.htm

vital tool in reaching British Columbia's energy goals, because utilities have a long-established relationship with their customers, with frequent customer communications, and because customers look to their energy providers for information about managing energy consumption. Going forward, the Utilities look to secure long-term funding for EEC activities to continue supporting customers in managing their energy consumption and costs, ensuring the efficient use of natural gas, and backing British Columbia's energy needs and policy goals. Later in this section, the Utilities present a review of three future funding scenarios to help identify energy and GHG emissions savings potential and guide further analysis and discussions regarding future EEC funding.

5.3 EEC Programs Overview

The current portfolio includes our conventional EEC Residential, Commercial, and Affordable Housing programs, as well as some NGV initiatives. These programs will be implemented through 2011 and are projected to conserve over 12,000,000[108] GJs for the entire planning period, which is equivalent to heating ~126,000 homes[109] for one year (please refer to Appendix C for a full list of 2009 and 2010 programs). However, we have reason to believe that the total savings might be underestimated for two reasons. Firstly, the portfolio does not incorporate energy savings from Innovative Technologies (besides some NGV activities) or Interruptible Industrial programs. These areas are new to the EEC portfolio and new initiatives are not expected to be implemented until late 2010 and 2011; given that the Utilities have not previously had programs in these areas, and have no experience in estimating savings for these areas, we felt that a conservative approach would be appropriate. Once there are programs up and running, savings from Interruptible Industrial and Innovative Technologies programs will be incorporated into the portfolio benefit/cost analysis. Secondly, the Terasen Utilities are not only focusing on reducing energy consumption through a variety of incentive and upgrade programs, but also by inducing conservation behavioural changes through Education and Outreach. Conservation from behavioural changes, however, has not been incorporated into the Utilities' savings portfolio because of the difficulty tracking results from individual actions. Nevertheless, the Utilities believe that there is a significant potential to decrease consumption through the Education and Outreach activities. For example, turning off pilot lights in fireplaces during the summer, can reduce the energy consumption of a household by ~4 GJs[110] for the season.

Current EEC initiatives can be divided into two components: conservation activities and high carbon fuel switching activities. High carbon fuel switching programs[111] were approved by the

[108] We estimate conventional EEC programs will conserve a cumulative total of 14,000,000 GJs over the next 20 years, while conversions and adoptions of NGVs are expected to increase demand by 2,000,000 GJs in total.

[109] Based on a home utilizing 95 GJs per year, the average of Terasen's current Rate 1 (Lower Mainland Residential) customers.

[110] 1035 BTU's/ cubic ft. X 24 hours/day X 30 days/month = 745,200 BTU's/month Because 1 GJ = 948,213 BTU's, the pilot light will use .7859 GJ's/month

[111] High Carbon fuel switching programs encourage customers to convert from higher carbon fuels such as propane, diesel, and oil to natural gas.

Commission as an EEC initiative because they reduce GHG emissions, increase the efficiency of the Terasen Utilities infrastructure and lower the system cost per user which in turn reduces energy costs for customers. These activities align with the government's goal to reduce GHG emissions by 80% by 2050[112]. A prime example of high carbon fuel switching activities is incentives for NGVs, which is reviewed in Section 5.4.2.

Going forward, we propose to create programs that support a holistic approach to energy efficiency, including whole building initiatives such as labelling and the move to a performance-based building code. We will continue to develop initiatives intended to assist low-income households in reducing energy consumption, making rental accommodations more energy efficient, as well as developing programs for students in the Utilities' service areas.

5.3.1 EEC FOR CUSTOMERS IN TERASEN GAS (WHISTLER) INC.

TGW has not traditionally offered EEC programs because the customer base in the TGW service territory has historically been quite small, and recovery of EEC costs spread over the small number of customers in TGW was thought to result in unacceptably high rate impacts. While TGW did not claim any EEC program savings from the Whistler conversion, the project was instrumental in achieving carbon emission reductions through high to low carbon fuel switching and provides an improved energy platform for future EEC activity. In response to community interest in participating in EEC programs, TGW plans to include funding for EEC activity in its RRA for 2012. The CPR that we will be conducting in late 2010 will provide insight into potential programs that can be implemented in the TGW service area.

5.4 New EEC Program Areas Commencing in Late 2010

5.4.1 INTERRUPTIBLE INDUSTRIAL CUSTOMERS

TGI believes that there is significant potential for a reduction in Interruptible Industrial[113] consumption. Initiatives are currently being developed for this segment, but it is not yet clear how future load will be affected by conservation efforts. To assist TGI in determining the size and nature of EEC opportunities for this sector, an overall analysis of the industrial sector will be included in the CPR, which will be conducted in late 2010. In contrast to some of TGI's other consumer segments, special consideration must be given to mitigating the risks associated with large financial investments in energy efficiency for interruptible industrial customers and the resulting magnitude of the anticipated energy savings. The Terasen Utilities have hired an Industrial Program Manager to begin working with key stakeholders in this segment and developing programs to be implemented in 2011.

---

[112] Greenhouse Gas Reductions Targets Act, 2008
[113] Interruptible industrial customers include customer classes 7, 22 and 27.

5.4.2 INNOVATIVE TECHNOLOGIES

Innovative Technologies are defined as market ready technologies that have little or no market penetration in British Columbia. The Terasen Utilities' incentives for this portfolio are designed to promote emerging technologies. The current portfolio of Innovative Technologies includes Solar Thermal Hot Water, NGV, Hydronic and Combination Heating Systems, Residential Ground Source Heat Pump ("GSHP") Systems and Commercial/Industrial GSHP Systems. We are conducting market research to determine potential programs for these technologies, and their associated savings. It should be noted that the technologies in this portfolio and the resulting impact on load are subject to change depending on market conditions, including adoption rates and introduction of new technologies.

The NGV market shows particular promise for this portfolio. As a result of potential EEC incentives, the City of Vancouver, City of Surrey, City of Port Coquitlam and other third party partner have all expressed interest in converting some of their current high carbon diesel fleet into NGVs, and purchasing new NG trucks for garbage disposal. Switching to natural gas as a transportation fuel reduces GHG emissions by displacing higher carbon fuels like diesel and gasoline, and by adding load, optimizes use of the gas distribution system.

5.5 Beyond 2011- Future EEC Funding Scenarios

5.5.1 IMPACT ON ENERGY DEMAND AND EMISSIONS

TGI and TGVI's current EEC budget expires on December 31, 2011. We are planning to submit a request for on-going funding as part of the 2012 RRA for both TGI and TGVI. We believe additional funding for EEC activities will benefit multiple stakeholders. Through various consultation activities and regulatory processes, the Utilities' customers and other stakeholders have indicated support for increased and ongoing funding due to the additional customers that can be reached and savings that can be achieved through the continuous and consistent availability of EEC programming.

To determine what level of ongoing funding should be implemented; we examine the potential impact on natural gas demand and GHG emissions in three scenarios of future funding for EEC programs below. It should be noted that the scenarios have been

Taking Leadership in Development of Solar Projects

Solar Homes Pilot is a program in partnership with Terasen, City of Vancouver, SolarBC and Offsetters, financing up to 50 percent (about $3,500) of the cost of installing a sola hot water system, which will be available to 50 new houses on a first-come, first-servec basis, beginning January 2010 through March 2011.

developed using the best available data, but will be updated once the results of the CPR are received. These scenarios are discussed below in detail.

- **Funding Scenario A**

This is the "status quo" scenario, which assumes that the currently approved funding and resultant EEC activity will cease after 2011. The expected energy savings in this case are based on the programs planned from 2009 to 2011, and the number of participants and measure life of equipment were determined using the best available data[114]. Scenario A assumes that these funding levels are not renewed and revert back to pre-2009 levels of ~$4 million.

We believe the savings from this scenario are underestimated for a number of reasons. The energy savings from industrial programs have not been incorporated into this scenario, as they are currently in the development phase. Also, the Utilities are still developing the Innovative Technologies portfolio, and have only incorporated the expected increase in demand from the replacement of high carbon diesel heavy-duty trucks with low carbon natural gas by 2011. As NGV demonstration projects and first adopters in the province show success, we expect that markets will begin to grow and assumptions used to calculate energy savings will have to be revised as that data becomes available. Finally, the total energy conserved is likely underestimated in this case because savings from behavioural changes and some Commercial DSM programs have also been excluded due to difficulty estimating the conservation impact of these activities, even though there is significant energy savings potential.

Should this scenario come to fruition, the Terasen Utilities and our customers will be subjected to all of the pitfalls of inconsistent and uncertain funding and growth in energy savings and the resultant emission reductions will cease.

- **Funding Scenario B**

To develop Scenario B, the Utilities have assumed the same funding levels, approximately $35 million annually, that were awarded in 2010 and 2011 will be sustained until the end of the long range planning period (i.e. from 2012 until 2030)[115]. The following is a list of assumptions used to build this scenario, though they may change as data on new programs and market potential becomes available from the CPR:

- Conventional EEC programs similar to that in Scenario A will continue to be implemented throughout the planning period.

---

[114] The total savings are subject to change based on programs and technologies available, as well as participant uptake rate.

[115] The net energy savings calculated are based on the following assumptions in absence of any information on future programs and participation rates.

- The measure life and participation rates will remain constant at the 2010 levels for all the planned programs.
- The same number of incremental vehicles that were assumed in Scenario A in 2011 will be funded every year until 2030. This is a conservative estimate but is based on the most recently available data and successes.
- Industrial programs and the possibility of other programs being developed under the Innovative Technologies portfolio are excluded under this scenario.

➢ **Funding Scenario C**

The third scenario assumes that funding will be fixed at 5 per cent of the Terasen Utilities' annual revenues, which would equate to ~$80 million in 2012. This represents funding of slightly more than twice currently-approved funding levels, and was felt by the Utilities to be a reasonable starting point for funding a highly aggressive approach to EEC. Terasen Utilities recognize that the success of its initiatives will help transform the market throughout the planning period, and the scenario assumes that funding levels and associated savings begin to taper off by $5 million annually starting in 2022. To reiterate, this scenario has been developed using the best available data, but timelines and funding level requirements may change once the results of the CPR become available, or as we progress through the planning period. We believe that funding increases will be necessary to expand the current EEC programs and implement new initiatives. For example, increased funding will allow for the implementation of a large-scale accelerated stock retirement program for inefficient heating systems, further development of industrial programs, expansion of NGV initiatives across broader market segments, and other Innovative Technologies projects.

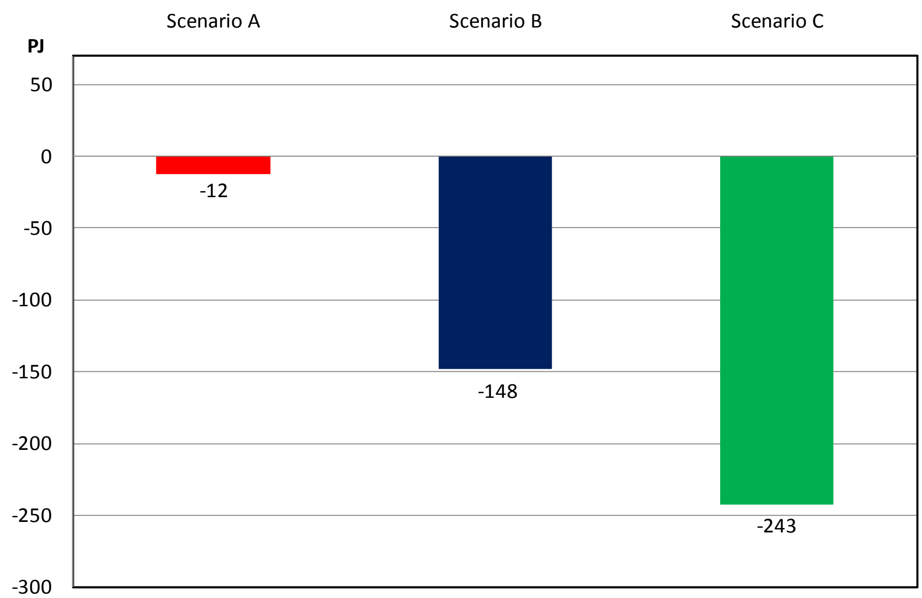
For the purposes of estimating the net savings in Scenario C, we have assumed the following:

- No funding will be allocated to additions of other natural gas transportation, such as transit vehicles or marine transportation, due to the absence of thorough information for these particular end uses at this point in time.
- All the funding for transportation has been allocated to heavy vocational trucks (waste haulers), heavy duty trucks (tractor trailers), medium trucks (postal vans). This may change as additional data and customer interest develops, as Terasen Utilities hopes to use EEC funding to help alleviate the initial capital cost for sectors such as marine and transit vehicles in order to reduce GHG emissions.
- The Utilities will only be claiming the consumption and GHG emissions reduction from the adoption of vehicles that were accelerated by EEC funding. In other words, the Utilities acknowledges that NGVs will gain market share in the future, but strongly believes that EEC funding is instrumental to transform the market and Terasen Utilities can therefore claim a portion of those savings.

5.5.2 IMPACT ON ENERGY SAVINGS AND GHG REDUCTIONS IN SCENARIOS A, B, & C

Each of the scenarios described above will have a significantly different impact on energy conserved. Figure 5-1 depicts the impact on energy savings from the above mentioned scenarios. As can be seen, Scenario C will conserve significantly more energy than Scenario A, 213.38 PJs (equivalent to 213,380,000 GJs) versus 11.75 PJs (11,750,00 GJs)[116.]

Figure 5-1: Year 2009 - 2030 Cumulative Natural Gas Savings from EEC Scenarios



Given that Scenario A is based on current, approved funding for EEC, the current demand forecast presented in Section 4.2.6 includes this level of energy savings. The impact of Scenarios B and C on the Reference Case current demand forecast is shown in Figure 5-2. Although the scale of energy savings against total energy demand may appear small on this graph, the declining consumption in Scenarios B and C occurs in conjunction with continued customer additions and results in significant cumulative energy and GHG savings as shown in Figure 5-2 and 5-3. Scenario C will aid in reducing GHG emissions by more than 16,000,000 tonnes, versus Scenario A which would reduce GHG emissions by more than 820,000 tonnes.

[116] The total cumulative savings have been calculated using the sum of energy conserved from conventional EEC programs and efficient load building from the addition of NGVs.

Figure 5-2: Impact of EEC Scenarios B and C on Reference Case Demand - 2010-2030 (All Utilities)

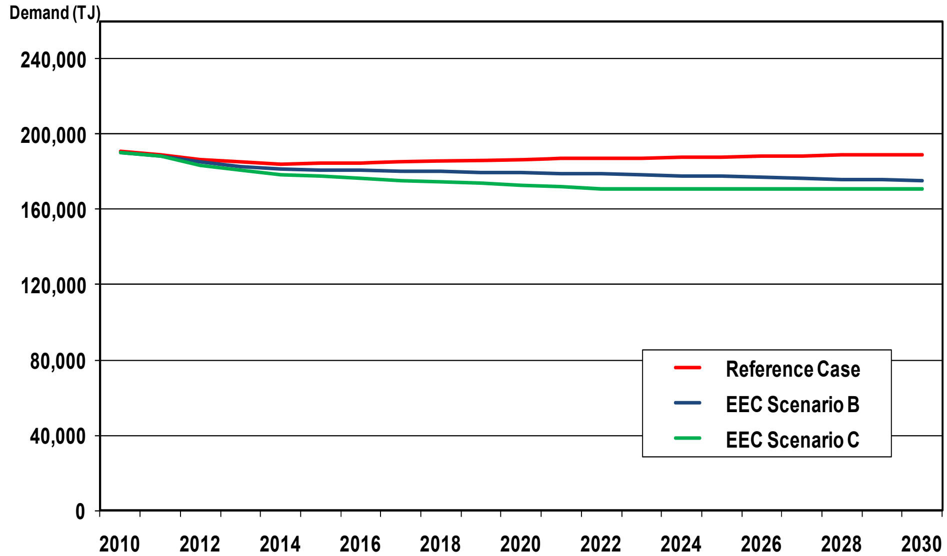
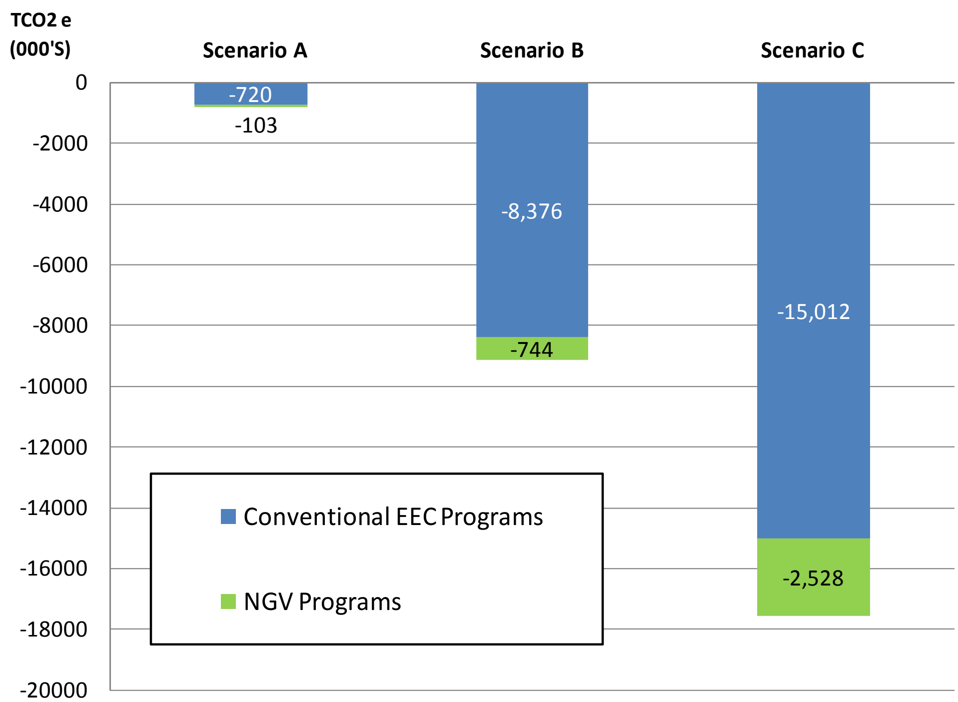


Figure 5-3: Year 2009 - 2030 Cumulative GHG Savings from EEC Scenarios



5.6 Managing Uncertainties in Developing and Implementing EEC Programs

A number of factors can influence the effectiveness and impact of EEC initiatives. Terasen Utilities have taken a variety of factors into consideration when estimating how EEC activities will impact demand. This section summarizes some of those factors and how they are managed.

5.6.1 IMPACT OF NEW AND CHANGING EQUIPMENT EFFICIENCY REGULATIONS AND BUILDING CODES AND STANDARDS

The B.C. government's aggressive GHG emissions reduction goals have led to the proposal and implementation of a variety of building codes and standards, as well as equipment efficiency regulations that impact the EEC initiatives primarily by providing the Utilities with areas of support for market transformation efforts in support of these proposed regulations and building codes and demand for natural gas.

5.6.1.1 British Columbia Building Code

The provincial government has recently announced that they are working toward the implementation of a new provincial residential building code that will be equivalent to Energuide 80 rating to take effect in late 2010[117]. The current rating of 77 and the new 80 rating are stepping stones toward a "Net Zero Community Energy"[118] level set for 2020. The primary goal of the building code revision is Net Zero energy utilization[119], with a secondary goal of Net Zero GHG emissions. Preliminary analysis has shown that this may lead some customers to adopt electric equipment for space and water heating, due to lower upfront capital costs[120]; however, the Utilities believe that the energy cost of using natural gas in the long run will be lower and therefore benefits the customer. Terasen Utilities can play a part in mitigating the impact of this regulation by working with industry professionals to identify the prescriptive construction measures so that individuals and organizations can meet the building code requirements while continuing to use natural gas for space and water heating. The Utilities will also play a role in communicating the benefits of high efficiency natural gas equipment to customers, and supporting the government in enforcing regulation.

---

117 "The Province is developing a Building Code change proposal to require energy performance for new Part 9 housing that, combined with provisions under the BC Energy Efficiency Act, will be equivalent to EnerGuide 80" from http://www.housing.gov.bc.ca/building/green/index.htm

118 These buildings will be the most energy efficient ever constructed in British Columbia to minimize the need for energy supplies. While those buildings will require purchased energy from utilities, these will be offset through the generation of heat and power from on-site or community-based, clean and renewable energy resources. (http://www.empr.gov.bc.ca/EEC/ProgramsActionsInitiatives/NetZero/Pages/default.aspx)

119 A net zero home at a minimum, supplies to the power grid, an amount equal to the total amount of energy consumed.

120 Higher capital cost is derived from the equipment and installation cost, and the requirement for ventilation and air circulation systems.

5.6.1.2 Proposed Water Heater Regulations

Water heating represents the second largest household energy usage, equating to approximately 20% of household energy use in Canada[121]. The federal and provincial government have announced plans to introduce a three-tier efficiency plan leading to a regulation requiring a minimum energy efficiency factor ("EF") of 0.80 as shown in Table 5-2.

Table 5-2: Three Tier Water Heater Efficiency Plan Summary

Type	Minimum Efficiency	Effective Date
Gas Storage- 151 L Water Heater	0.62 EF	September 1, 2010
Gas Storage- 189 L Water Heater	0.61 EF	September 1, 2010
Gas Storage Water Heater	0.67 EF	TBD
Gas Storage Water Heater	0.80 EF	TBD

* For the first two items, EF rating is based on a formula EF= 0.70 – (0.0005*V)
** V=volume of storage water tanks in liters
***Storage tank volumes of 151 L and 189 L are typical residential heater sizes

In order to reach 0.80 EF, water heater manufacturers will need to use tankless or condensing technology. Terasen Utilities have been joined by manufacturers of natural gas heaters in voicing concerns with the proposed regulation, as there are currently no condensing water tanks that are appropriately sized for the residential market. Terasen Utilities have identified that there is a major risk to gas water heating load as both tankless and condensing technologies have different venting requirements than technologies generally installed today, and tankless technologies may not be appropriate for some applications. Furthermore, both technologies have significantly higher upfront capital costs than electric alternatives. The result may be load shifting from natural gas to electric water heating, with a spill over loss to space heating. We are working alongside our partners, including the government and manufacturing industry, to ensure that technologies are available and proven before the regulation is implemented.

5.6.1.3 Home Heating Systems Regulation

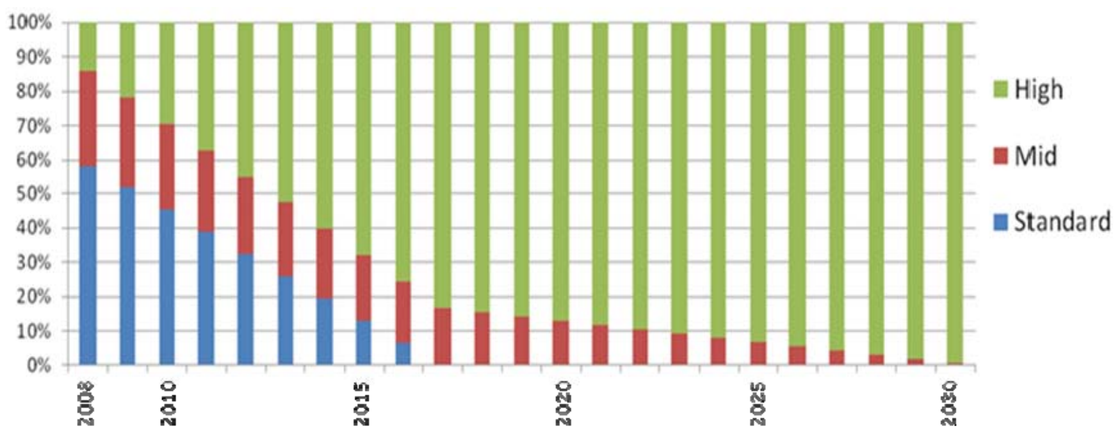
Terasen Utilities assisted in preparing the B.C. residential market for the furnace regulation passed by the Province in 2009, which states that gas furnaces manufactured on or after December 31st, 2009 must have a minimum fuel efficiency level of 90% Annual Fuel Utilization Efficiency ("AFUE"). We began providing information and offering rebates to customers in support of this regulation in 2001. Terasen Utilities have used a variety of marketing techniques to increase adoption rates including bill inserts, internet, print media, radio, sales force efforts, relationship building with industry professionals, and customer outreach at community events and trade shows. Our goal in offering rebates for furnaces was to transform the market until the regulation was implemented, as it has now been. However, preliminary research has shown that there is still a high percentage of mid and low-efficiency stock available for sale in the marketplace.

---

[121] Condensing DHW Study: Habar & Associates Consulting Inc, March 2010

For example, as of 2009, almost 80% of furnaces in TGI service territory were low or mid efficient, and given current adoption rates, it could take up to 20 years for all furnaces installed to be high efficiency[122]. We have reason to believe this 20 year time period is understated, as these estimates were designed with the assumption that most people would replace their furnaces once they reach an expected service life of 18 years. Without incentives in place to support the early retirement of stock, some customers may keep their furnaces for as long as 30 or 40 years, which data from the 2008 REUS revealed is already happening in the TGI customer base. The Utilities believe that a Terasen-run furnace retirement program would be a significant contribution to achieving the Province's energy and greenhouse reduction goals. Unfortunately the existing benefit-cost tests that are currently applied to utility DSM programs are not the appropriate analysis tool for initiatives such as a furnace early retirement program as they do not recognize benefits beyond the avoided cost of energy, such as contributions to the greater policy goal of greenhouse gas emission reductions. Terasen Utilities are working on a proposal for such a program which would include a proposal for the appropriate evaluation of programs that support policy objectives, and hope to bring such a proposal before stakeholders for feedback within the next year. Figure 5-4 displays the breakdown by efficiency level of furnace stock in the TGI service territory.

Figure 5-4: Furnace Market Broken Down by Efficiency Level – TGI



5.6.2 SUPPORT FOR CODES, STANDARDS, AND REGULATIONS

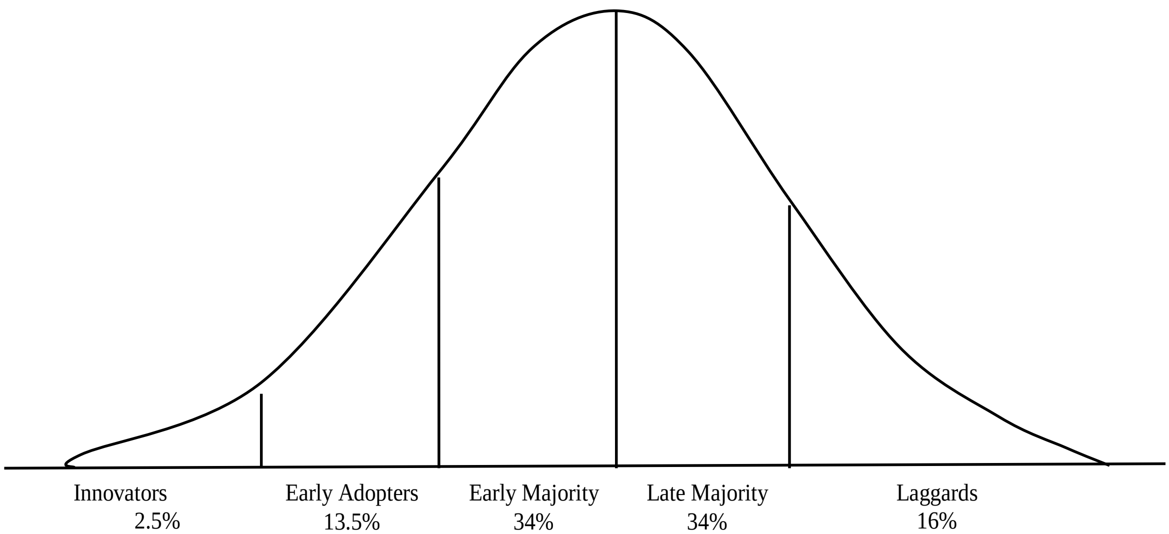
The Terasen Utilities work alongside various levels of government in developing and implementing codes, standards, and regulations. We believe that government regulation is a critical final step in transforming markets to adopt energy efficient equipment.

[122] 2008 Residential End Use Study- Sampson Research

5.6.2.1 The End Goal of EEC: Market Transformation

The end goal of the Utilities' EEC programs[123] is market transformation, which can be defined as transforming the market to a point where energy efficient equipment/systems/buildings are the new baseline for regulation. Market transformation utilizes the concepts of "Diffusion Theory," which state that innovation occurs in five stages for consumers, to shift the curve shown in Figure 5-5 to the left, and encourage adoption of new technologies faster than would occur organically. EEC programs are developed to address barriers which prevent consumers from adopting energy efficient appliances.

Figure 5-5: Market Diffusion Curve



One of the outcomes of market transformation is regulation through Codes and Standards. Prematurely aggressive efficiency target levels, with a lack of equipment and service history to meet these performance levels could slow down or stop market transformation. This could result in substantial load shift to other energy sources, disturbing the energy supply balance thus effecting energy delivery rates to all customers. One example of this is our work on analyzing impacts of British Columbia's proposed water heater regulation. The Terasen Utilities hired Habart & Associates Consulting to provide a strategy paper which assesses the impact of the water heater regulation and provides a conceptual framework for transforming the market to support the introduction of the proposed water heater regulation. We believe an increase in EEC funding will be required to provide incentives that encourage manufacturers to develop residential 0.80 EF water heater technologies, and to educate the marketplace on the benefits of the systems.

[123] This goal is defined in Principle #12 of the Terasen Utilities' EEC Application, 2008. http://www.terasengas.com/_AboutUs/RatesAndRegulatory/BCUCSubmissions/LowerMainlandSquamishInterior/EnergyEfficiencyConservationPrograms/default.htm

5.6.3 RISKS ASSOCIATED WITH PROGRAM SAVINGS ESTIMATES

A challenge in developing EEC programs is estimating program uptake rates and energy savings. There are a number of factors that affect participation rates including emergence of new technologies, economic conditions, the political climate, changes in adoption rates for current technologies, energy price fluctuations, changes in consumer behaviour and consumption patterns, and initiatives by other utilities or government. Inconsistent incentive funding hinders program development, as staff cannot develop programs with long term goals in mind, and communications with participants and market factors such as equipment installers about program lifetimes are erratic.

5.6.4 MITIGATING THE PROGRAM SAVINGS ESTIMATION RISKS

The Terasen Utilities take analysis of energy impacts from EEC activity very seriously and obtains up-to-date market information about different technologies to ensure accuracy. When developing programs, we review the inputs and savings through formal engineering estimates, ongoing market research studies and program evaluation. Terasen Utilities carefully monitor assumptions and inputs on program costs, participation rate, energy savings per participants, and incentive amounts to ensure efficient use of funding. The Terasen Utilities contract with external third parties to evaluate programs and assess their marketplace success.

Terasen Utilities also conduct a CPR every few years to examine the technologies available in the marketplace and determine the "conservation potential," including the amount of energy savings that can be achieved through EEC. The CPR analyzes the potential impacts of identified energy efficiency and fuel choice programs and initiatives to a base case scenario, and acts as the guiding document in designing future programs. The 2009 EEC decision approved funding for an updated CPR, understanding that the study is a fundamental piece in developing DSM initiatives. The results from the 2010 CPR will be imperative in determining how EEC activities are going to impact demand and will help Terasen Utilities:

- Develop a long range energy efficiency and fuel choice strategy, including an analysis of the savings opportunities available from the implementation of the above mentioned scenarios and large-scale, Alternative Energy Systems;
- Design and implement energy efficiency and fuel choice programs and initiatives;
- Assess the impact of energy efficiency and fuel choice program on both peak and annual loads;
- Identify equipment and technologies that could be used for energy efficiency and fuel choice programs, including new technologies that are commercially available but have very low market penetrations
- Set annual energy efficiency and fuel choice targets and budgets

In addition, the Utilities have requested a discussion paper as part of the CPR that reviews how our energy efficiency and conservation efforts could support government policy. The paper should detail potential alternative EEC analysis approaches that look beyond the traditional economic focused California Standard Practice tests. These tests were developed to support “traditional” utility energy efficiency activity, and only consider the avoided costs of energy and the costs associated with energy efficiency activity, which is a very narrow view of energy efficiency activity in the larger context of support for long-term government policy goals. Based on these economically focussed analysis tools as they are defined in the California Standard Practice Manual, the Terasen Utilities would not be able to engage in such programs as a furnace replacement initiative, funding the full cost of furnace upgrades for low-income households, or implementing geo-exchange systems for schools, all of which are laudable initiatives that support government’s larger GHG emissions reduction goals. The Utilities look forward to working with government and other key stakeholders in developing more suitable analysis tools for utility EEC programs that support government policy goals, but that are not seen as “cost-effective” when viewed through the narrow lens of the California Standard Practice Tests.

In conclusion, the results from the 2010 CPR will be imperative in determining how EEC activities are going to impact demand and will form the primary basis of Terasen Utilities EEC funding requests for 2012 and beyond.

5.7 Conclusion

While TGI and TGVI is currently implementing programs and activities as a result of the increased EEC funding from Orders G-36-09, G-141-09 and G-140-09, which approved a total of $72.315 million in EEC expenditure over 2010 and 2011, still more can be done. For market transformation efforts to take hold, approved utility EEC funding needs to be of sufficient magnitude to support market transformation efforts, and stable and long-term enough to provide consistency in utility communications and activities with customers, market players and stakeholders. For this LTRP, Terasen Utilities analyzed 3 Scenarios, and concluded that in Scenario C, where EEC funding is approved up to 5 per cent of gross utility revenues, EEC activity could make a significant contribution of 16,000,000 tonnes of GHG reduction to government’s GHG emissions reduction targets. Such a funding envelope would allow for a significant NGV uptake in the medium and heavy-duty “return to home” fleet market, a furnace retirement program and a water heater market transformation program.

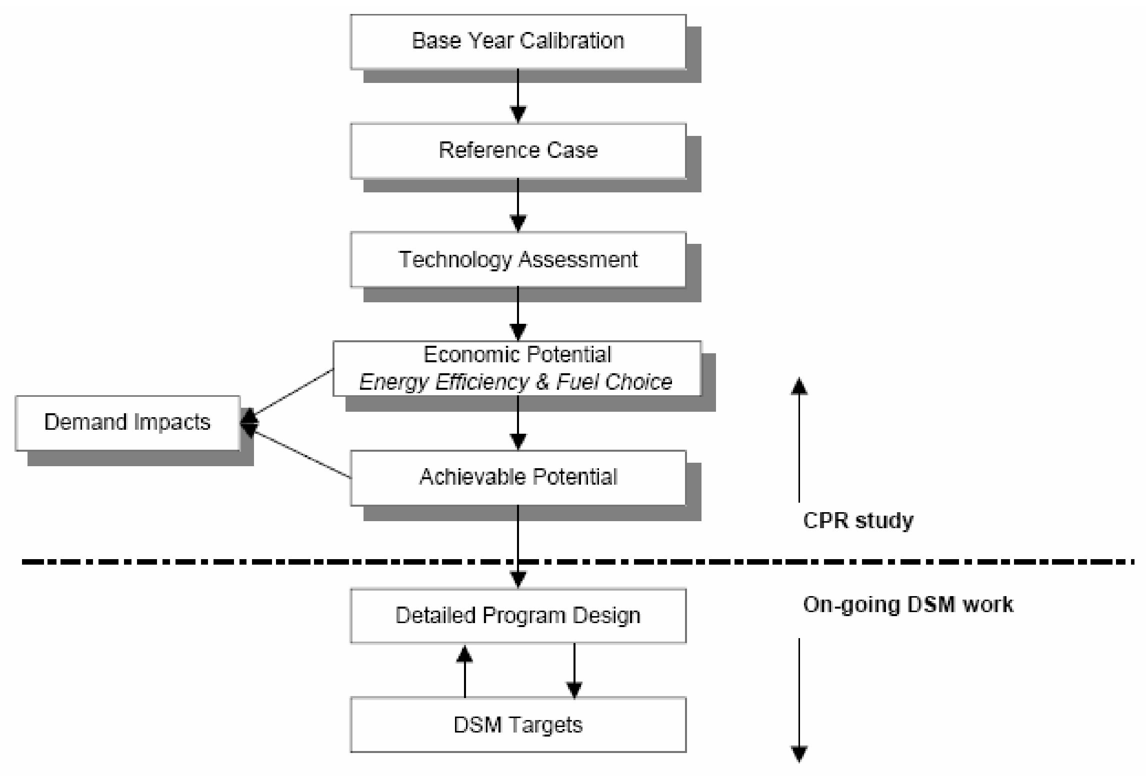
The Utilities will be conducting an updated CPR that will support an application for approval of EEC funding in the future 2012 RRA. The results of this CPR will be imperative in determining how EEC activities are going to impact demand for 2012 and beyond. Further, Terasen Utilities have concluded that the California Standard Practice tests may not be the appropriate analysis tool for Utility EEC programs of the future.

4. Conservation Potential Review

As stated in the 2004 Annual Review, at that time the Companies had started preliminary work on an extensive CPR study designed to analyze the amount of DSM potential in different geographical areas in the Companies' service territory. At the time the study was commissioned by the Companies, the intent was to submit an application to the Commission for increased DSM activity, based on the outcome of the CPR. This Application fulfils that original intent.

In May 2006, the Companies received the final CPR from Marbek. The process for the CPR was described extensively in the 2006 Resource Plans for TGI[23] and TGVI.[24] The major steps involved in the CPR analysis are shown in Figure 4 below.

Figure 4 - Conservation Potential Review Process Flow



[23] Terasen Gas Inc., 2006 Resource Plan, pages 54 - 64
[24] Terasen Gas (Vancouver Island) Inc., 2006 Resource Plan, pages 55 - 63

The key finding of the CPR was the Achievable Potential. Achievable Potential is the proportion of savings identified in the Economic Potential Forecast that could realistically be achieved within the study period. Achievable Potential recognizes that it is practically difficult to induce customers to purchase and install all the energy efficiency or fuel choice options that are defined by the Economic Potential Forecast. It should be noted that the estimation of Achievable Potential is not synonymous with either the setting of specific program targets or with program design. For both utilities combined, the Achievable Potential from the CPR is outlined in Table 4.1 below.

Table 4.1 - CPR Findings

By 2015/2016, GJ per year	TGVI	Lower Mainland	Interior	Total
Residential EE	-369,000	-5,298,000	-1,847,000	-7,514,000
Commercial EE	-385,000	-1,396,000	-431,000	-2,212,000
Industrial EE	-32,430	-933,064	-924,210	-1,889,704
Subtotal	**-786,430**	**-7,627,064**	**-3,202,210**	**-11,615,704**
Residential Fuel Subsitution				1,453,000
Potential Annual Impact				**-10,162,704**

Please note that this Application does not include a request for funding for Industrial Energy Efficiency activity as it was defined in the CPR. Energy Efficiency activity for Industrial customers is discussed in Section 6.10.

Work on converting the CPR results to DSM programs commenced in the fall of 2006, after the completion of the Resource Plans for TGI and for TGVI. In early 2007, Habart was commissioned by the Companies to rescreen and summarize the results of the CPR, and to assist with preliminary program design such that estimates of incentive levels, program uptake rates and program costs could be developed and a budget developed as the basis for this Application. The Habart report is attached as Appendix 9.

Both the CPR and the subsequent Harbart analysis found significant opportunity for increased conservation and efficiency activity by the Companies. In fact, the CPR confirmed the existence of significant potential cost-effective natural gas efficiency improvements in British Columbia's residential and commercial sectors. The Marbek study states, for instance, that:

> *"A significant increase in annual DSM investment and in program and incentive funding by Terasen Gas and its delivery partners would be required; this increase would be in the range of 3 to 5 times current levels. This level of investment would be consistent with current investment levels in other Canadian jurisdictions, such as Ontario."*[25]

The CPR also found that interactions between the Terasen Utilities and the Companies' customers would increase very significantly:

> *"Furnace and fireplace actions combined, could affect up to 25% of residential customers by 2015/2016."*[26]

This increase in interaction between the Terasen Utilities and customers is beneficial because it increases the opportunities for the Companies to communicate general conservation information in addition to program-specific information at the time of customer interaction. This amplifies the effectiveness of program and conservation communications expenditures.

Opportunities for increased activity derived from the CPR are discussed in more detail in Section 6. Approval for the funding required for that increased activity is requested in Section 2, "Application".

[25] Terasen Gas Conservation Potential Review, Residential Sector Report, April 2006, Marbek Resource Consultants in association with Habart and Associates and Innes Hood Consulting, page E-xi.
[26] Ibid

5. Program Principles

Below, the Terasen Utilities have identified the key principles that guided the selection of particular EEC initiatives and programs within the program areas identified in this Application, and would guide the development and implementation of the initiatives and programs should the increased EEC funding be approved. Many of the principles are based on the "DSM Best Practices" report prepared for the Canadian Gas Association in 2005 by IndEco Consulting in association with B. Vernon and Associates, which is attached at Appendix 10.

1. Programs will have a goal of being universal, offering access to energy efficiency and conservation for all residential and commercial customers, including low income customers through the DSM for Affordable Housing initiative.
2. Wherever possible, programs will be uniform, so that customers in one part of the service territories of the Terasen Utilities have access to the same programs as customers throughout the service territories.
3. EEC expenditures will be efficient, with non-incentive costs not exceeding 50% of the expenditure in a given year.
4. Program results will be analyzed on a portfolio-wide basis.
5. The Total Resource Cost/Benefit of the Portfolio over the funding period will have a ratio of 1 or higher
6. The Terasen Utilities will submit an Annual EEC Report to the BCUC, by the end of the first quarter of each year, that details the results of the previous year's programs and anticipates program activity and spending for the upcoming (current) year.
7. To every extent practical, programs will support the objectives of established government policies.
8. The Companies will continue to seek funding for programs from additional sources, such as the provincial and federal governments, other utilities, and equipment suppliers and manufacturers, in order to minimize the cost impacts of EEC programs to ratepayers, and in recognition of the broader societal benefits resulting from successful program development and implementation.
9. Incentives may be directed to the end users of an appliance, to the customer point of contact at the time that an equipment purchase decision is made (for example, to the gas contractor in the case of a furnace), to a system designer or engineer, or to an

equipment developer, supplier or manufacturer. The most effective use of incentives will be determined through the program design process.

10. Education and outreach regarding conservation will be part of the Companies' EEC activity.
11. Programs will be multi-year so as to create a sense of funding certainty necessary to effective implementation in the marketplace – this Application requests funding for a three-year Portfolio of EEC programs.
12. Programs will have market transformation as their ultimate goal, and program plans will describe how a program will contribute to market transformation.
13. Programs will aim to develop capacity within the market through manufacturers, distributors, vendors and installers.
14. To ensure value creation and alignment with the market, the Companies will establish and engage an EEC stakeholder group, comprised of governments, industry, trades, manufacturers, NGOs, advocacy groups, other utilities and customers to provide it with advice on effective program design and implementation, as well as some oversight of the Companies' EEC activity and expenditure. Consideration may be given by the Companies to consolidate the Terasen Utilities' EEC Stakeholder activity with stakeholder activity currently being undertaken by other utilities in order to reduce potential "stakeholder fatigue".

6. Expanded Funding and EEC Program Proposal

This Section provides more detail about the specific items in this Application for which the Companies are requesting Commission approval. The Companies have long been focused on promoting conservation and responsible energy use, and the progression of economic and environmental factors and societal expectations necessitates a revised approach to the funding and creation of programs in support of this objective.

6.1. Increase Funding to EEC Program Area

The Terasen Utilities request approval for overall expenditures for the EEC Program Period in the amount of approximately $46.9 million for TGI and approximately $9.7 million for TGVI, for a total of approximately $56.6 million. The Companies are proposing incremental EEC/DSM expenditures over three years of $40.696 million for TGI and $7.366 million for TGVI. On a combined basis, the total additional funding for the three years ending 2010 over and above the approved levels stipulated in Extended Settlements for the two years ending 2009 is $48.062 million, bringing the three year total for both Companies to $56.61 million. The annual total per utility is outlined in Table 6.1 below.

Table 6.1 - Proposed EEC expenditures, by Utility ($000's)

Utility	2008	2009	2010	Total by Utility
TGI	$13,996	$15,752	$17,196	$46,944
TGVI	$2,830	$3,043	$3,793	$9,667
Subtotal by year	$16,826	$18,795	$20,990	$56,611

These proposed expenditure figures are "budget year" totals; that is they are the amount of the total proposed EEC budget by year in the year that the funds would be spent or committed. Further, these are the figures for the Terasen Utilities' contribution to energy efficiency and conservation initiatives. In instances where there are electricity savings from a certain measure, the Companies anticipate partnering with electrical utilities and potentially, governments, to deliver joint programs. Partner funding is discussed further in Section 6.2.2.

The Companies have developed the overall proposed expenditure in Table 6.1, for which approval is sought, based on the allocation of funding to the program areas as outlined in Table

6.1a. The program areas that the Companies intend to pursue with approval of this Application are expanded over the program areas currently addressed. The Companies intend to pursue the following program areas of EEC activity for each utility for both residential and commercial customers: Energy Efficiency and Fuel Switching measures, Conservation Education and Outreach activity, Trade Relations, Joint Initiatives, and Innovative Technologies, Natural Gas Vehicles ("NGV") and Measurement. For funding beyond 2010, the Companies propose that a CPR be commenced in 2009, to determine potential areas of energy efficiency and conservation program for the period 2011 to 2014. It is proposed that a submission to the Commission would be made by the Companies in 2010, based on the findings from the 2009 CPR, for funding for the period 2011 to 2014. Additional funding, estimated at $500,000 for the CPR is included in the $56.6 million total for which approval is being sought. Once this Application is approved,, the Companies would proceed to an Request for Proposals for the CPR.

The allocation of funding as among the program areas was derived with reference to specific initiatives contemplated within each program area.

Table 6.1a - Proposed EEC Expenditure by Program Area by Utility

Spend by Program Area 2008 - 2010	TGI	TGVI	Total
Residential Energy Efficiency	$8,552	$734	$9,286
Commercial Energy Efficiency	$19,592	$2,199	$21,791
Residential Fuel Switching	$1,332	$2,367	$3,699
Conservation Education and Outreach	$11,068	$2,767	$13,835
Joint Initiatives	$2,400	$600	$3,000
Trade Relations	$1,200	$300	$1,500
Conservation Potential Review	$400	$100	$500
Innovative Technologies, NGV and Measurement	$2,400	$600	$3,000
Total	**$46,944**	**$9,667**	**$56,611**

The Companies believe that it is most efficient for the Commission to approve the overall expenditure level, by utility, for the Funding Period, rather than approving the funding by program area, or by individual program initiative. This approach will allow the Companies' to respond quickly to changes within initiatives and to new opportunities that might arise. For example, if a particular initiative within the commercial energy efficiency program area has a higher than expected number of participants, and a strong cost-benefit ratio, the Companies would like to have the ability to shift funds from another, underutilized program area to that commercial energy efficiency initiative, without coming back to the Commission for approval to do so. Not only will this allow the Companies' to respond quickly to opportunities, it will also reduce the Companies' administrative burden related to EEC activity, and both the speed of response and reduced administrative burden will increase the value to customers of the Companies' EEC activity.

The funding level adjustments are warranted as levels have not been adjusted in many years. The increase proposed will bring the Terasen Utilities' EEC funding closer to the levels of other utilities' EEC spending. As a point of comparison with other utilities, the level of funding proposed for 2008 amounts to approximately 1% of projected gross revenue for 2008, a significant increase over current funding levels of approximately 0.26% of gross revenues. When considering EEC Activity on a per customer basis, approval of the Companies' expenditure as outlined above would mean that in, for example, 2009, the Companies would spend approximately $20 per customer on EEC, an increase from the current expenditure of approximately $5 per customer, but well below BC Hydro's proposed Power Smart expenditure for F2010 at over $60 per customer.

The Terasen Utilities believe that the proposed overall EEC expenditure will provide greater cost-effective assistance to customers manage their energy costs, and support the government's energy objectives as defined in Bill 15 and detailed in the 2007 Throne Speech and the Energy Plan. The Companies will continue to assess over the course of the Program Period whether customers would benefit from additional EEC spending over and above the funding sought in this Application, and will bring forward any further application as appropriate.

6.2. EEC Program Area Budget Development Process

The budget numbers for residential energy efficiency, for commercial energy efficiency, and for residential fuel switching were developed based upon the work done in 2006 in the CPR. The CPR was received by the Companies in May 2006. At a high level, funding allocations for the activities planned are outlined in Table 6.1a. While a CPR can provide an estimation of Achievable Potential, more work must be done to develop a DSM plan based upon a CPR. From the Residential section of the CPR:

> *"…the results of this CPR study, and in particular the estimation of Achievable Potential, support on-going DSM planning work. However, it should be emphasized that the estimation of Achievable Potential is not synonymous with either the setting of specific program targets, or with program design."*[27]

Therefore the Companies retained the services of Habart early in 2007 to assist with further program and budget development. The methodology used by Habart in developing the budget estimates for residential energy efficiency, commercial energy efficiency and residential fuel switching is detailed in Appendix 9. At a high level, the measures explored in the CPR were re-screened to determine which might be the best candidates for further program development work. For each promising measure, estimates were developed of the incentive dollars needed to elicit participation, program uptake, and non-incentive costs (administration, marketing and promotion, and evaluation). Estimates were derived using internal expertise, as well as external data sources such as residential new construction rates. The measures and associated incentive and non-incentive budgets were then screen in accordance with the California Standard Practice Manual (attached as Appendix 12) tests for cost-effectiveness, and the measures with a TRC of 1 or greater were included in budget development.

6.2.1. Consumer Education and Outreach

The Conservation Education and Outreach budget figure was developed in consultation with the Companies' advertising agency. The Companies approached their advertising agency, requesting an initial action plan and associated costing for a Conservation Education campaign, aimed at the public, of the magnitude of the Customer Choice campaign. The advertising agency responded with a plan, and after some discussion between the Companies and the agency, and subsequent refinement of the plan, a cost for such a campaign was derived. The outline for the plan, and the associated budget, is attached as Appendix 8.

[27] Terasen Gas Conservation Potential Review, Residential Sector Report, April 2006, Marbek Resource Consultants in association with Habart and Associates and Innes Hood Consulting, pages E-i and E-ii, Marbek and

6.2.2. Joint Initiatives, Trade Relations and the 2009 CPR

The amounts for Joint Initiatives, Trade Relations and the 2009 CPR were developed by the Companies based on the Companies' best estimates of potential expenditure levels for these three program areas. The Joint Initiatives program area is estimated to require funding of approximately $1 million per year, however more funding may be required for this program area if additional opportunities for initiatives with partners should arise. Should this occur, the Companies would expect to shift funds from under-performing areas to this program area. The Trade Relations program area is estimated to require funding of approximately $0.5 million per year and this would cover one staff member, and various outreach activities aimed at trade allies, as described in Section 6.7. The estimate for the 2009 CPR is based upon a cost to perform the previous CPR of approximately $300,000, and includes an allowance for the kind of work done by Habart to refine the CPR results into a DSM program. The amount for Innovative Technologies, NGV and Measurement will need to be refined – if an effective program in Innovative Technologies, NGV and Measurement can be developed over the funding timeframe, the Companies wish to have to the ability to fund such a program over the funding timeframe.

The analysis and budget derivation presented above in Table 6.1 and in the following Table 6.1a does not include an anticipated contribution from BC Hydro or from other partners for electrical savings. The total amounts for all programs, including partner contributions from BC Hydro or others for those commercial energy efficiency measures where there are electrical savings, are presented in Table 6.2b (Please note that the contributions outlined are only for incentives for electrical savings in certain commercial initiatives; there is zero partner contribution assumed for the fuel switching initiatives, nor is there a contribution contemplated for non-incentive expenditures such as promotion costs.)

It should be noted in the Tables 6.2a and 6.2b below showing the breakdown of EEC expenditures proposed by the Companies adheres to the Principle #9 regarding efficient spending as discussed in the previous Section 5 on "Program Principles". Incentives comprise just over $30 million of the total proposed three year expenditure of $56.6 million. Therefore non-incentive program costs are proposed to be under 50%, as outlined in the principle regarding efficient spending.

Table 6.2a - Proposed EEC Expenditure Detail - TGI and TGVI

			Budget Amount - Terasen Only								
			2008			2009			2010		
Utility	**Sector**	**Nature of Program**	**Incentives**	**Program Costs**	**Total**	**Incentives**	**Program Costs**	**Total**	**Incentives**	**Program Costs**	**Total**
TGI	Residential	Conservation Potential Review	$0	$0	$0	$0	$200,000	$200,000	$0	$0	$0
TGI	Residential	Energy Efficiency	$1,925,000	$981,000	$2,906,000	$2,350,000	$874,000	$3,224,000	$1,675,000	$747,000	$2,422,000
TGI	Residential	Fuel Switching	$195,000	$164,000	$359,000	$270,000	$139,000	$409,000	$345,000	$219,000	$564,000
TGI	Commercial	Energy Efficiency	$3,245,700	$1,289,000	$4,534,700	$4,640,000	$1,643,000	$6,283,000	$6,223,050	$2,551,000	$8,774,050
TGI	Residential	Joint Initiatives	$600,000	$200,000	$800,000	600000	$200,000	$800,000	$600,000	$200,000	$800,000
TGI	Residential	Conservation Education and Outreach	$0	$2,098,000	$2,098,000	0	$1,718,000	$1,718,000	$0	$1,718,000	$1,718,000
TGI	Residential	Trade Relations	$0	$200,000	$200,000	0	$200,000	$200,000	$0	$200,000	$200,000
TGI	Commercial	Conservation Potential Review				0	$200,000	$200,000			
TGI	Commercial	Conservation Education and Outreach	$0	$2,098,000	$2,098,000	$0	$1,718,000	$1,718,000	$0	$1,718,000	$1,718,000
TGI	Commercial	Trade Relations	$0	$200,000	$200,000	$0	$200,000	$200,000	$0	$200,000	$200,000
TGI	Residential	Innovative Technologies, NGV and Measurement	$400,000	$0	$400,000	$400,000	$0	$400,000	$400,000	$0	$400,000
TGI	Commercial	Innovative Technologies, NGV and Measurement	$400,000	$0	$400,000	$400,000	$0	$400,000	$400,000	$0	$400,000
TGVI	Residential	Conservation Potential Review				$0	$50,000	$50,000			
TGVI	Residential	Energy Efficiency	$86,000	$97,000	$183,000	$168,000	$54,000	$222,000	$257,000	$72,000	$329,000
TGVI	Residential	Fuel Switching	$401,000	$276,000	$677,000	$558,000	$198,000	$756,000	$731,000	$203,000	$934,000
TGVI	Commercial	Energy Efficiency	$310,090	$111,000	$421,090	$470,490	$136,000	$606,490	$922,490	$249,000	$1,171,490
TGVI	Residential	Joint Initiatives	$150,000	$50,000	$200,000	$150,000	$50,000	$200,000	$150,000	$50,000	$200,000
TGVI	Residential	Conservation Education and Outreach	$0	$524,500	$524,500	$0	$429,500	$429,500	$0	$429,500	$429,500
TGVI	Residential	Trade Relations	$0	$50,000	$50,000	$0	$50,000	$50,000	$0	$50,000	$50,000
TGVI	Commercial	Conservation Potential Review				$0	$50,000	$50,000			
TGVI	Commercial	Conservation Education and Outreach	$0	$524,500	$524,500	$0	$429,500	$429,500	$0	$429,500	$429,500
TGVI	Commercial	Trade Relations	$0	$50,000	$50,000	$0	$50,000	$50,000	$0	$50,000	$50,000
TGVI	Residential	Innovative Technologies, NGV and Measurement	$100,000	$0	$100,000	$100,000	$0	$100,000	$100,000	$0	$100,000
TGVI	Commercial	Innovative Technologies, NGV and Measurement	$100,000	$0	$100,000	$100,000	$0	$100,000	$100,000	$0	$100,000
		Subtotals	$7,912,790	$8,913,000	$16,825,790	$10,206,490	$8,389,000	$18,795,490	$11,903,540	$9,086,000	$20,989,540

Table 6.2b below provides a <u>total</u> budget figure, including assumed contributions to joint programs from partners for electrical savings from certain Commercial sector initiatives. There is no assumed contribution from partners for avoided electricity load resulting from the proposed residential fuel switching activities, or for incidental electricity savings resulting from natural gas energy efficiency initiatives in the residential sector.

Table 6.2b - Proposed EEC Expenditure Detail - TGI, TGVI and Partners

			Budget Amount Including Partner Contributions								
			2008			2009			2010		
Utility	**Sector**	**Nature of Program**	**Incentives**	**Program Costs**	**Total**	**Incentives**	**Program Costs**	**Total**	**Incentives**	**Program Costs**	**Total**
TGI	Residential	Conservation Potential Review	$0	$0	$0	$0	$200,000	$200,000	$0	$0	$0
TGI	Residential	Energy Efficiency	$1,925,000	$981,000	$2,906,000	$2,350,000	$874,000	$3,224,000	$1,675,000	$747,000	$2,422,000
TGI	Residential	Fuel Switching	$195,000	$164,000	$359,000	$270,000	$139,000	$409,000	$345,000	$219,000	$564,000
TGI	Commercial	Energy Efficiency	$4,112,700	$1,289,000	$4,534,700	$6,162,500	$1,643,000	$6,283,000	$8,749,050	$2,551,000	$8,774,050
TGI	Residential	Joint Initiatives	$600,000	$200,000	$800,000	$600,000	$200,000	$800,000	$600,000	$200,000	$800,000
TGI	Residential	Conservation Education and Outreach	$0	$2,098,000	$2,098,000	$0	$1,718,000	$1,718,000	$0	$1,718,000	$1,718,000
TGI	Residential	Trade Relations	$0	$200,000	$200,000	$0	$200,000	$200,000	$0	$200,000	$200,000
TGI	Commercial	Conservation Potential Review	$0	$0	$0	$0	$200,000	$0	$0	$0	$0
TGI	Commercial	Conservation Education and Outreach	$0	$2,098,000	$2,098,000	$0	$1,718,000	$1,718,000	$0	$1,718,000	$1,718,000
TGI	Commercial	Trade Relations	$0	$200,000	$200,000	$0	$200,000	$200,000	$0	$200,000	$200,000
TGI	Residential	Innovative Technologies, NGV and Measurement	$400,000	$0	$400,000	$400,000	$0	$400,000	$400,000	$0	$400,000
TGI	Commercial	Innovative Technologies, NGV and Measurement	$400,000	$0	$400,000	$400,000	$0	$400,000	$400,000	$0	$400,000
TGVI	Residential	Conservation Potential Review	$0	$0	$0	$0	$50,000	$50,000	$0	$0	$0
TGVI	Residential	Energy Efficiency	$86,000	$97,000	$183,000	$168,000	$54,000	$222,000	$257,000	$72,000	$329,000
TGVI	Residential	Fuel Switching	$401,000	$276,000	$677,000	$558,000	$198,000	$756,000	$731,000	$203,000	$934,000
TGVI	Commercial	Energy Efficiency	$348,490	$111,000	$421,090	$532,890	$136,000	$606,490	$1,477,790	$249,000	$1,171,490
TGVI	Residential	Joint Initiatives	$150,000	$50,000	$200,000	$150,000	$50,000	$200,000	$150,000	$50,000	$200,000
TGVI	Residential	Conservation Education and Outreach	$0	$524,500	$524,500	$0	$429,500	$429,500	$0	$429,500	$429,500
TGVI	Residential	Trade Relations	$0	$50,000	$50,000	$0	$50,000	$50,000	$0	$50,000	$50,000
TGVI	Commercial	Conservation Potential Review	$0	$0	$0	$0	$50,000	$50,000	$0	$0	$0
TGVI	Commercial	Conservation Education and Outreach	$0	$524,500	$524,500	$0	$429,500	$429,500	$0	$429,500	$429,500
TGVI	Commercial	Trade Relations	$0	$50,000	$50,000	$0	$50,000	$50,000	$0	$50,000	$50,000
TGVI	Residential	Innovative Technologies, NGV and Measurement	$100,000	$0	$100,000	$100,000	$0	$100,000	$100,000	$0	$100,000
TGVI	Commercial	Innovative Technologies, NGV and Measurement	$100,000	$0	$100,000	$100,000	$0	$100,000	$100,000	$0	$100,000
		Subtotals	$8,818,190	$8,913,000	$17,731,190	$11,791,390	$8,589,000	$20,380,390	$14,984,840	$9,086,000	$24,070,840

Table 6.2c below provides the net assumed contributions from partners to joint programs for electrical savings from Commercial Initiatives.

Table 6.2c - Summary Table, EEC Contributions by Partners

Net Assumed Partner Contribution											
		2008			2009			2010			Totals
Utility	Sector	Incentives	Program	Total	Incentives	Program	Total	Incentives	Program	Total	2008 - 2010
TGI	Commercial	$867,000	$0	$867,000	$1,522,500	$0	$1,522,500	$2,526,000	$0	$2,526,000	$4,915,500
TGVI	Commercial	$38,400	$0	$38,400	$62,400	$0	$62,400	$555,300	$0	$555,300	$656,100
	Totals			**$905,400**			**$1,584,900**			**$3,081,300**	**$5,571,600**

The total assumed contribution from partners is approximately $5.5 million and does not include any non-incentive costs such as program promotion costs. The assumed contribution is for electrical savings in the Commercial sector only. If partner funding was not available for electrical savings, the natural gas initiatives for the Commercial sector would proceed, but on the basis of providing incentives for natural gas savings alone, rather than combining incentives for natural gas and electrical savings. This assumed contribution does not include any contribution from partners for Residential Fuel Switching programs.

6.3. Energy Efficiency Program Areas

Under the Companies' current guidelines, customer-level marketing and energy efficiency activities for the Lower Mainland and Interior are different from those for Vancouver Island. For the Lower Mainland and Interior, DSM activities at TGI are focused solely on peak shaving and conservation initiatives (also termed "energy efficiency" throughout this document) that aim to reduce natural gas usage by customers, and do not encompass other aspects of DSM such as load building through encouraging fuel switching. TGVI currently only offers customers fuel switching programs, and does not offer customers energy efficiency programs. With this Application, the Companies would like to expand EEC activities so as to offer all customers, regardless of service territory, access to an expanded array of programs. That is, the Companies would like to be able to offer customers on Vancouver Island access to energy efficiency programs and would like to offer Lower Mainland and Interior customers access to fuel switching programs.

The information presented in this sub-section regarding energy efficiency program areas is done so sector (Residential and Commercial) basis. The Residential and Commercial sectors are broken down into initiatives intended for new construction and initiatives intended for the retrofit market. Fuel substitution program area and activities are described under Section 6.4.

6.3.1. Residential Energy Efficiency Program Area ($9.2 million)

Energy Efficiency programs for the residential sector fall under two types of offers – new construction and retrofit. They are summarized in Table 6.3.1 below.

Table 6.3.1 - Residential Energy Efficiency

Program	Components	TGI	TGVI
Residential Energy Efficiency – New Contruction			
EnerChoice Fireplace	EnerChoice Fireplace	X	X
ENERGY STAR Appliances	E* Clothes Washer	X	X
	E* Dish Washer	X	X
Residential Energy Efficiency - Retrofit			
ENERGY STAR Furnace Upgrade	E* Furnace	X	X
EnerChoice Fireplace Upgrade	EnerChoice Fireplace	X	X
ENERGY STAR Appliance Upgrades	E* Clothes Washer	X	X
	E* Dish Washer	X	X

Energy Efficiency for Residential New Construction

The program is targeted at all potential residential new construction customers. It is intended to be complementary to the Companies' System Extension and Customer Connection Policies Review Application, submitted to the BCUC July 31, 2007. In Order No G-152-07 of December 6, 2007 the Commission stated that "Terasen is encouraged to apply for the approval for such [DSM] programs in another forum, where their impact and efficiency as DSM programs can be tested." This document constitutes the Companies' Application for DSM programs for the New Construction market. The key decision makers in this market for the programs detailed below are builders and developers who build single family homes and row-houses. In addition, a number of single-family homes are project-managed by the owners themselves who make planning and purchasing decisions and could be considered in an outreach campaign. There may also be some builders of multi-family dwellings that participate in the incentive programs outlined below. The new construction EEC portfolio in the residential market will include programs that encourage customers, whether they be individuals building a new home, or builders and developers, to install energy efficient appliances. The following programs will be offered to customers and builders:

EnerChoice Fireplace - an incentive will be provided to encourage the purchase and installion an EnerChoice rated fireplace, insert or free-standing stove. (Since there is no Energy Star designation for fireplaces, the Hearth Products Industry has developed the EnerChoice designation, which is applied to fireplaces that are in the top 25% efficiency ranking out of all the fireplaces available in the marketplace.)

Energy Star Clothes Washer and/or Dishwasher – similar to the program offered to customers in the retrofit market, participants who use natural gas as a heating source for Domestic Hot Water ("DHW") will be encouraged to install an Energy Star dishwasher and/or Energy Star clothes washer. The incentive amount will be based on whether they choose to install one or both appliances.

Energy Efficiency for Residential Retrofits

The retrofit program targets all existing residential customers of the Terasen Utilities. The key decision makers in this market are owners and possibly landlords of single-family and row-houses who are either replacing failed equipment or looking to upgrade/improve energy efficiency in existing housing stock.

The retrofit programs will consist of a combination of advertising and promotion and incentives for customers who install Energy Star and/or EnerChoice rated products.

Energy STAR Heating System Upgrade – this program will be a reiteration (since similar versions of this program have been running for a number of years) of the TGI Energy Star Heating System Upgrade program. Customers who install an Energy Star heating system will receive a credit on their Terasen Utilities bill. It should be noted that due to new federal regulations for furnace upgrades in retrofit residential buildings coming into effect December 31, 2009, this program will conclude prior to that date.

At the time that the CPR was conducted, there were found to be a total of 1,534,248 residential units in the TGI service area, of which 155,809 units were pre-1976 single family dwellings ("SFD") or duplexes with gas.[28] These dwelling units would be good candidates to upgrade existing furnaces to high-efficiency models. To contextualize the projections used to derive the

[28] Terasen Gas Conservation Potential Review, Residential Sector Report, Marbek Resource Consultants, April 2006, page 8

funding levels in this Application, the Application contemplates funding a total of 8,180 furnace upgrades up to the end of 2009, at which time a federal regulation is proposed that would make 90% efficiency levels the minimum for all furnaces sold in Canada so utility incentive funding is assumed to cease. This incentive participation level represents funding for incentives for furnace upgrades in 5.3% of pre-1976 single family dwellings ("SFDs") and duplexes with gas in the Companies' service territory, and it is based upon current program participation rates.

EnerChoice Fireplaces – customers will be incented if they purchase and install an EnerChoice rated fireplace, insert or free-standing stove. The pilot program will be launched in 2008 in partnership with Hearth, Patio & Barbeque Association of Canada (HPBAC) who will provide assistance in promotional and educational aspects of the program.

Energy Star Appliances – existing customers who use natural gas as a heating source for Domestic Hot Water ("DHW") will be encouraged to install an Energy Star dishwasher and/or Energy Star clothes washer. The incentive amount will be based on whether they choose to install one or both appliances. These measures provide savings by reducing the amount of water that needs to be heated by gas, but they also result in ancillary electricity savings from more efficient electric motors.

The Energy Star Heating Upgrade Initiative has existed in different forms since the current level of DSM funding available to TGI was established in 1997. In the 1997 DSM Semi-Annual Status Report, submitted by BC Gas Utility Ltd. on November 19, 1997, the number of participants in the heating upgrade program was 68 at the time of reporting, projected to grow to 205 by year-end. This year's program, running as noted above from September 1 2007 to March 31 2008 is projected to have 3300 participants, a notable gain in program participation.

6.3.2. Commercial Energy Efficiency Program Area ($21.7 million)

As with the residential sector, energy efficiency initiatives for the commercial sector will also fall under retrofit and new construction programs.

Energy Efficiency for Commercial New Construction

The new construction program is targeted at all commercial new construction which might use natural gas space and water heating. Looking at current new commercial construction, the immediate opportunities are likely to be Multi-Family Dwellings (“MFDs”) and Commercial office space. Eligible buildings may also include some institutional (government buildings, schools and post-secondary institutions). It should be noted that incentives, building design and heating and hot water systems for MFDs are covered by the program proposals below, in the Commercial Section of this program activity description, rather than in the Residential Section.

The key decision makers in this market are owners including: governments; builders/developers; architects; engineers; interior designers; mechanical consultants; and contractors.

Table 6.3.2 below lists some potential areas for activity in the Commercial New Construction sector. Program design is complex in the Commercial New Construction sector, so the table below merely summarizes areas of program activity.

Table 6.3.2 - Commercial Energy Efficiency - New Construction

Program	Components	TGI	TGVI
Efficient New Construction	Efficient Design (30% Below Current Practice, Large Commercial Buildings)	X	X
	Efficient Design (30% Below Current Practice, Medium Commercial Buildings)	X	X
	Efficient Design (60% Below Current Practice)	X	X
	High Insulation Technology (HIT) Windows	X	X
Boilers	Near Condensing Boilers	X	X
	Condensing Boilers	X	X
Water Heating	Instantaneous DHW Heaters	X	X
	Condensing DHW Boilers	X	X
	Condensing DHW Heaters	X	X
	Drainwater Heat Recovery	X	X

Energy Efficiency for Commercial Retrofits

The commercial retrofit program is targeted at all commercial and industrial buildings with existing natural gas fired space and water heating equipment. These include, but are not limited to:

- MFDs and commercial office space;
- Institutional (any government buildings, post-secondary campuses and schools);
- Hospitals;
- Hotel/motel buildings;
- Malls.

The key decision makers for retrofit equipment replacement decisions are building managers and owners.

There are two drivers for replacing/upgrading existing equipment in retrofit markets: equipment at the end of life and products that are replaced before the end of life to obtain energy efficiency savings. The table below lists some potential areas for activity in the Commercial retrofit market. Due to the potential complexity of programs for the commercial sector, Table 6.3.2a below merely summarizes areas of program activity. More detailed program development work must be completed by the Companies in conjunction with industry groups before these programs are rolled out.

Table 6.3.2a - Commercial Energy Efficiency - Retrofits

Program	Components	TGI	TGVI
Boilers	Near Condensing Boilers	X	X
	Condensing Boilers	X	X
Building Recomissioning		X	X
Next Generation Building Automation Systems (“BAS”)	Next Generation BAS	X	X
Demand Control Ventilation (“DCV”)	DCV (Large Commercial Buildings)	X	
	DCV (Medium Commercial Buildings)	X	
High Efficiency (“HE”) Rooftop Units	HE Rooftop units	X	X
Water Heating	Instantaneous DHW Heaters	X	X
	Condensing DHW Boilers	X	X
	Condensing DHW Heaters	X	X
	Drainwater Heat Recovery	X	

Programming for the Commercial sector in general is intended to offer qualified commercial customers a menu of programs from which to choose. Terasen Utilities staff will work with the participants in selecting the most appropriate program and/or component.

6.4. Residential Fuel-Switching Program Area ($3.7 million)

The Terasen Utilities firmly believe that the use of natural gas where available for high-efficiency end-use appliances in place of electricity results in lower GHG emissions overall in the region, as it makes more of BC's "green" electricity resource available to its best use to displace coal and lower efficiency gas fired generation throughout the region.[29]

Fuel substitution initiatives benefit all customers by ensuring that the Terasen Utilities' distribution infrastructure is used to its maximum efficiency. This is especially true of TGVI, where homes that have not made the step to connect to gas exist in proximity to gas mains. Existing customers have already invested in putting those gas mains in the ground, therefore connecting as many customers as possible to the natural gas distribution system will keep overall system costs down. It should be noted that the fuel switching activity for the retrofit market is focused on Vancouver Island, and would be based on encouraging residents in the TGVI service area to get off oil, and onto efficient natural gas, resulting in lower GHG emissions. Table 6.4 below summarizes at a very high level the program areas for fuel switching activity.

Table 6.4 - Residential Fuel Switching

Program	Components	TGI	TGVI
Residential Fuel Switching – New Construction			
Natural Gas Water Heating	NG DHW		X
Natural Gas Appliances	NG Range	X	X
	NG Dryer	X	X
Residential Fuel Switching – Retrofits			
Natural Gas Appliances	FS Range		X
	FS Dryer		X
Furnace Fuel Substitution	Furnace		X
Fireplace Fuel Substitution	EnerChoice Fireplace		X

[29] Coal and gas fired generation are on the margin throughout the western interconnection. New combined cycle gas turbines operate at only approximately 50% efficiency, whereas newer natural gas water heaters and space heaters can operate as high as 95% efficiency.

Fuel Switching for Residential New Construction

Provincial regulations taking effect January 1, 2008, require that all natural gas forced air furnaces in all new construction meet the Energy Star standard. This presents two major areas of concern from the perspective of fuel efficiency and GHG emissions. As discussed previously, gas water and space heating is more efficient and results in lower GHG emissions on a regional basis than electric space and water heating. First, the higher relative cost of the Energy Star rated natural gas furnaces may persuade some builders to switch to electric space heat. Second, non-Energy Star natural gas furnaces were able to be vented in such a manner ("b-vented") that the vent for the furnace could be shared with the vent for a natural gas hot water tank. Energy Star furnaces cannot share a vent with a natural gas hot water tank, so the regulation for Energy Star furnaces may cause builders to install electric hot water installations to avoid the cost of venting for the already more expensive natural gas hot water tank.

To encourage the usage of natural gas among its customers, the Terasen Utilities would offer the following fuel-substitution programs:

Installation of **natural gas water heating** along with natural gas space-heating equipment – the Companies may bundle this program as a package with Energy Star appliances.

Installation of **natural gas range** and/or **dryer** – TGVI and TGI qualified applicants will receive an incentive if they install one or both appliances.

The primary objective of the fuel-switching offers is to promote the most optimal balance in energy share between electricity and natural gas, preserving BC Hydro's generation and transmission systems for its highest value – in running lights, computers and other technology.

Fuel Switching for Residential Retrofits

TGVI has been running residential programs on Vancouver Island and the Sunshine Coast for a number of years. These programs have encouraged owners of existing homes on Vancouver Island and the Sunshine Coast to convert from higher emission propane and fuel oil to natural gas. Incentive funding for fuel substitution retrofits is only contemplated for TGVI and not for TGI, as it is felt that the bulk of the potential in the TGI service territory has already been addressed. The benefits from fuel substitution programs for existing homes on Vancouver

Island as described below are significant: GHG emissions are reduced through the switch from wood, propane or fuel oil to natural gas for space heating and fireplaces, and BC Hydro and BCTC avoid adding additional capacity to serve water heating, cooking and clothes drying load on an already stressed transmission and distribution system. TGVI would like to initiate a fuel-substitution portfolio intended to retrofit homes on Vancouver Island to include the following programs:

Natural Gas Heating System Upgrade - customers who switch to a natural gas heating system in an existing home will receive an incentive from Terasen Gas. Existing residences in the TGVI service territory will be offered an incentive not only for switching to natural gas, but also for installing Energy Star equipment. The current regulatory regime for TGVI does not allow Terasen to offer customers who switch to natural gas an incentive to install Energy Star equipment. We would like to be able to do so and would in fact restrict the provision of an incentive to furnaces and boilers rated Energy Star.

Fireplace - customers in existing homes will be incented if they purchase and install an EnerChoice rated fireplace, insert or free-standing stove.

Natural Gas Range and Dryer – these two additional fuel-switching programs will encourage customers to replace their existing electric or propane range and/or an electric or propane dryer to a natural gas range and/or dryer.

6.5. Conservation Education and Outreach Program Area ($13.8 million)

In addition to program-specific education and outreach funding (that is, funding designed to communicate information to potential participants concerning a specific DSM program), the Terasen Utilities are also requesting funding with this Application for non-program-specific education and outreach activities as part of this program area. These are projected to include:

- Stakeholder industry group relations activities (for example, the first time homebuyers' and renovation seminars that are mounted by various homebuilder and realtor groups)
- Increasing the activity of "Team Terasen", a public outreach team that attends public events in the Lower Mainland, with a goal of informing the public about actions that they can take to improve the energy consumption of their homes

- Supporting conservation education within BC's schools
- Partnering with others to support an annual Energy Forum for British Columbia
- A comprehensive communications campaign, outlined in the attached proposal from Wasserman Partners, aimed at supporting the creation of a "culture of conservation" in British Columbia

The Conservation Campaign contemplates funding of $5.245 million in the first year, and $4.295 million per year in years two and three. The Companies feel that the greenhouse gas reduction goals of the Province will require a shift in consumer activity even more challenging to achieve than educating Terasen Gas' residential gas customers about the opportunity to sign a fixed rate contract with a gas marketer. As such, the level of spending being contemplated is higher than approved for Residential Unbundling. The key focus of the education and outreach initiative would be to educate customers, equipment installers, and the public at large about the importance and benefits of managing energy consumption.

6.6. Funding for Joint Initiatives Program Area ($ 3 million)

The Companies propose with this Application that $1 million per year in each of 2008, 2009 and 2010 be approved for development and pursuit of joint initiatives as they arise. Three such joint initiatives that the Companies will pursue if the Application is approved are outlined below. The funding of this program area will be used to support the initiatives of partners, and as such, the initiatives outlined below are those that the Companies are aware of today. Other Joint Initiatives may arise in the future, and if additional funding is warranted for future Joint Initiatives, the Companies intend to re-allocate funding from another program area if there is one that is under-spent. Alternatively, if all funds for each program area approved with this Application are expected to be used, the Companies would expect to make separate application to the Commission for approval of additional EEC expenditures for Joint Initiatives.

6.6.1. DSM for Affordable Housing

The Companies recognize that all British Columbians across all income sectors need access to energy efficiency programs. The low income sector is distinct in that there are significant capital and other barriers that are more difficult to overcome than in the "able to pay" market segments.

The natural priorities of this sector are such that many energy efficiency and conservation opportunities fall out of reach. The Ministry of Energy, Mines and Petroleum Resources has asked that the Terasen Utilities lead a working group on DSM for Affordable Housing. The Terasen Utilities' have convened the group, which has had three meetings to date. The goal of the working group is to find ways and means to deliver Energy Efficiency to the Affordable Housing sector in British Columbia. Funding for the Companies' participation in a DSM incentive program for the Affordable Housing sector will come from the Joint Initiatives allocation, if the Application is approved.

6.6.2. Support for Audits for a Provincial Home Retrofit Program

The Ministry of Energy, Mines and Petroleum Resources has expressed its intention to implement a province-wide home retrofit program, known as LiveSmartBC, to work with the Government of Canada's eco-Energy program. The Companies understand that the proposed provincial program does not currently contemplate funding for the post-retrofit audits that are required in order to claim the federal eco-Energy grants. One possible area of joint activity for the Companies and the Ministry would be for the Companies to fully or partially fund the post-audits required for the Companies customers to be able to claim the provincial and federal retrofit incentives available under this program. Customers would benefit by having a potential barrier to participation (the cost of the post-audit) reduced or removed, and would therefore be able to participate more readily in any such program. Funding for the Companies' participation in a post-retrofit audit program will come from the Joint Initiatives allocation, if the Application is approved.

6.6.3. Building Labeling

Policy Action 6 in the 2007 Energy Plan contemplates a pilot project for energy performance labeling of homes and buildings. Labeling buildings with information about building efficiency, and the resultant energy consumption and costs is a key part of informing the public about the importance of energy conservation. The Terasen Utilities intend to undertake a co-funding a pilot energy performance labeling program for new and existing gas-heated homes if the Application is approved. The amount of incremental DSM funding that Terasen would allocate to support such an initiative would be dependent on the size of the pilot program. Labeling benefits ratepayers by providing them with a means to compare energy consumption levels between homes. Building energy consumption labeling could be made a requirement for participation in incentive programs, particularly in new construction. Funding for the Companies' participation in a building labeling program will come from the Joint Initiatives allocation, if the Application is approved.

6.6.4. Community Action on Energy Efficiency ("CAEE")

The Companies have participated in the program committee for this provincial initiative (Policy Action #9 from the 2007 Energy Plan), and have contributed funds to print a policy manual that came out of Community Action on Energy Efficiency. The Companies believe this is a worthwhile initiative, since municipalities have the ability to influence the energy consumption levels of new construction in their communities through such processes and methods as permit costs and priorities, zoning changes and floor area ratio bonusing. The Companies would make a financial contribution to the pool of funds to which municipalities can apply under the CAEE initiative, should this Application be approved.

6.7. Trade Relations Program Area ($1.5 million)

The support and education of skilled trades, equipment manufacturers, distributors, suppliers and retailers, as well as appliance and equipment salespeople and Realtors, is crucial to the success of an Energy Efficiency and Conservation program. The funding being requested for Trade Relations with this Application will support the activities of a Terasen Utilities staff member focused on Trade Relations as it relates to energy efficiency. Areas of activity that the Companies will undertake following approval of the Application are anticipated to include the following:

- manufacturer and supplier relations initiatives
- working with trade associations to educate their membership on the benefits of various energy efficient technologies, as well as working to ensure that skilled tradespeople are adequately trained on the installation of energy efficient technology
- working with Home Builders Associations to educate their membership on the benefits of energy efficient homes
- working with Realtors' Associations to educate their membership on how to promote a homes' energy efficiency features

- working with manufacturers and distributors to ensure that energy efficient technologies are available in the marketplace
- working with appliance salespeople to educate them about the benefits to their customers of selecting a more energy efficient appliance

6.8. Conservation Potential Review ($500,000)

Funding is being requested with this Application to update the Terasen Utilities Conservation Potential Review in 2009. The updated Conservation Potential Review Study would be received in 2010, and would then form the basis of an application to the Commission for the next tranche of Energy Efficiency and Conservation funding for the period 2011 to 2014.

6.9. Innovative Technologies, NGV and Measurement Program Area ($3 million)

The Companies are in a unique position to foster and further the deployment of forward-looking low carbon technologies, including measurement technologies, and are therefore seeking funding with this Application, specific to this arena. The amount and activity for Innovative Technologies, NGV and Measurement will need to be refined – if an effective program in Innovative Technologies, NGV and Measurement can be developed over the funding timeframe, the Companies wish to have to the ability to fund such a program over the funding timeframe. The activity in this area would be in the nature of pilot programs, with limited time frames, geographic areas and number of installations. Some reasons that program activity would be considered not viable would be if the technologies prove to be prohibitively costly, or cannot be readily installed or serviced using local tradespeople, or are found to not provide adequate long term potential for widespread implementation.

This Section of the Application provides an overview of potential areas of opportunity for innovative technology investment that the Companies intend to pursue if the Application is approved. The information is divided into energy efficiency and fuel substitution activities, and by sector (Residential and Commercial).

It should be noted that the initiatives listed in this Section do not include all the innovative technologies that the Companies may pursue, but rather provide an overview of the types of initiatives the Terasen Utilities intend to pursue, all having the same underlying characteristics:

1) Each promotes the efficient use of natural gas through sustainable design
2) None are currently a mainstream technology
3) Each offers the potential for at least a 10% GHG benefit.

For all sectors, programs for fuel-substitution include plans that displace less efficient and dirtier fuels with natural gas or add cleaner renewable fuels to natural gas for further efficiency and GHG benefits.

Funding eligibility and incentive amounts are provided in Table 6.9.6 for budgetary purposes, but would require further analysis before implementation and would include both new construction and retrofit opportunities.

6.9.1. Innovative Technologies

This Section provides an overview of energy efficiency initiatives the Companies intend to pursue through the use of innovative technologies, if the Application is approved. The target market would include all residential and commercial applications.

Residential

Hydronic based heating systems - Hydronic heating systems use liquid (heated water or glycol usually) to distribute energy for space and domestic hot water heating through a supply and return closed-loop insulated piping system. The methods can include radiators, baseboards or fan coils, or a combination. The flexible nature of this system is that the heat input can be changed with changes in technology, knowledge or public policy, thus promoting a more sustainable energy design. Where an old low efficiency boiler might have been used an upgrade can be made to a high efficiency condensing boiler, and eventually a change could be made to supply heat to the water from biomass, ground or solar sources. By utilizing this type of system, an owner will be in a position to replace one type of heat source with another that is cleaner as technology advances. Given existing technologies, upgrading from a low-efficient boiler to a high efficient boiler could result in a 20-30% reduction in natural gas consumption. For the average family home this alone would be equivalent to 725 to 900 Kg of CO2e/yr.

The cost on average for hydronic underfloor system materials is estimated to be about $4,000, not including the boiler. The average cost of hydronic baseboard materials is estimated to be about $2,000, again not including the boiler.

In order to promote a sustainable energy design, the Companies would consider providing incentives up to 25% of cost of the hydronic underfloor piping materials (oxygen barrier tubing) to a maximum of $1,000 and hydronic baseboard materials up to 25% and a maximum of $500.

Integrated Energy Systems (or combo systems) - Integrated Energy or “combo” Systems are defined as a single appliance supplying both space and domestic hot water (DHW) heating. Combo heating systems can be cost effective and increase the operating efficiency of tank-style water heaters by reducing their normal standby energy losses. The hot water tank can be connected to a fan coil to provide forced air heating, and the fan coils can be upgraded to provide air conditioning as well. Combo systems can also be connected to in-floor tubing to provide in-floor radiant heat.

TGI is already encouraging efficient boilers in new construction with heat exchangers through the existing Efficient Boiler Program, although the smallest boiler is 300,000 Btu/hour, thus precluding residential boilers from this program. There is a possibility that more high efficient hot water tanks could be utilized in combo systems.

GHG savings would be accomplished through energy use improvements in domestic water heating. Standard gas hot water tanks are about 60% efficient and moving this part of the load to above 90% efficiency would certainly reduce GHGs.

A program to fund high efficiency (condensing) hot water tanks used for space and domestic hot water heating would help to drive demand for high efficiency gas hot water tanks. Right now these types of tanks cost about $3,000-$3,500 compared to $450-650 for a standard gas hot water tank. Installation costs would be comparable for both tanks. Instantaneous or tankless systems can be used for this Application as well. Given that the average single family dwelling consumes 25 GJs of gas for domestic hot water, moving from 60% to 90% efficiency would produce savings of about 8.3 GJs per household per year. This could equate to a reduction of about 400 kilograms/year of CO2e on the domestic hot water side. The Terasen Utilities would consider providing incentives up to 25% of total cost of condensing hot water tanks to a maximum of $1000. This would cover condensing instantaneous and condensing storage type of water heaters.

Solar thermal - A subset of hydronic heating systems, solar systems also use water or glycol heated by the sun, with the thermal energy transferred for domestic hot water or space heating. Solar space and water heating is usually supplemental to existing systems, reducing the requirement for the primary energy source used in the system.

Solar thermal space heating is cost prohibitive today and would likely add about $30,000 to the cost for average new home construction. Solar thermal domestic water heating costs about $8 000 for an average house and can be used as a supplement to the existing hot water tank to supply roughly half of the yearly water heating energy requirements.

Any solar energy usage results in GHG savings for that part of the load that it displaces. As a result, GHG production can be reduced by about 50%.

The average household uses approximately 25GJ/year for domestic water heating. If there was an annual reduction in gas usage of 12.5 GJ/year, that would reduce household greenhouse gas production by approximately 600 kilograms/year of CO2e.

The Companies would consider providing incentives of $500 towards solar pre-piping as long as a gas hot water tank is installed.

Commercial

As with the residential sector, energy efficiency programs for the commercial sector will include retrofit and new construction programs.

These include, but are not limited to:
MFDs and commercial office space;

Institutional (any government buildings, post-secondary campuses and schools);
Hospitals;
Hotel/motel buildings;
Malls.

Hydronic based heating systems – As with residential applications hydronic heating systems for commercial applications use water or glycol to distribute energy for space and domestic hot water heating through a supply and return closed-loop insulated piping system. In commercial applications or multi-unit residential buildings, the initial heat is usually supplied through a central boiler system. Along with supply through radiators, baseboards or fan coils, independent in-suite hydronic installations are available through compact boilers and dual mode hot water tanks. Again, the flexible nature of these systems is that the heat input can be changed with advances in technology, thus promoting the latest sustainable energy practices. Even further efficiencies can be gained in MFDs if suites are individually metered as there are studies that show 20 – 30% reductions in natural gas consumption and GHG emissions when consumption is measured and known.

The cost of a particular hydronic system is based largely on the size of commercial building. As with residential systems, the Companies are contemplating offering an incentive for a portion of the cost of either underfloor piping materials or hydronic baseboard materials in commercial buildings, including MFDs. Due to the high degree of variability in hydronic system installation costs in commercial buildings, further program development must be undertaken to develop an appropriate incentive level for this heating technology.

Solar thermal – For Commercial applications, solar heating can be a great fit with gas water and space heating. As with residential applications, solar heating is supplemental and allows reductions in gas use by as much as half. As a result GHG emissions can also be reduced up to 50%.

For commercial buildings the Companies would consider matching all or part of the ecoEnergy incentives which pay $10/GJ saved up to 25% of the project and up to $50,000 total. The GHG savings are easily calculated at .05 tonnes of CO2e/GJ conserved.

6.9.2. Fuel-Substitution Initiatives

Similar to the Innovative Technologies programs, the Terasen Utilities fuel-substitution initiatives will target new construction and retrofit markets in both TGI and TGVI. Fuel-substitution under this category refers to the displacement of natural gas using cleaner renewable technologies. GHG benefits will come from burning a cleaner fuel and or from blending such fuels with natural gas. Any overall energy efficiency gains combined with the volume of natural gas displaced results in fewer GHG emissions.

Due to the potential complexity of programs for this initiative, the discussion below merely summarizes areas of potential program activity. More detailed program development work must be completed by Terasen in conjunction with industry groups before such programs are rolled out. The Companies would only allocate funding to such initiatives if it appears that effective programs can be developed.

Residential

Hydrogen / Fuel Cell Power Generation - Hydrogen and hydrogen fuel cell projects currently appear to be some time away from being commercially viable. However, natural gas reformation is presently one of the most economic ways to produce hydrogen. The Companies are monitoring developments in this industry closely and are currently a member of Hydrogen Fuel Cells Canada. In some applications, burning hydrogen from natural gas reformation can be 30% more efficient than burning natural gas directly, and therefore, involvement in this field will likely continue to be important.

Stationary natural gas fuel cell projects for residential homes are currently underway in Japan where customers are seeing a 20-30% savings on their energy bill. This program is heavily subsidized by the government and would likely only be feasible on a small scale demonstration project.

The Companies would consider offering incentives on a trial basis for demonstration projects that support the hydrogen industry using natural gas as its primary fuel source.

Commercial

Biogas – the Terasen Utilities are in the process of conducting a feasibility study on the development of a biogas market in British Columbia and the role the Companies may play in the industry. TGI has been approached by a handful of parties interested in participating in a pilot project to inject pipeline quality biogas into its distribution system.

Preliminary economic analysis has determined that many biogas projects are unlikely to stand on their own from a financial perspective. As such, they would require subsidization or support through a relative premium paid for the commodity. TGI has been working with Metro Vancouver and their Lions Gate Treatment Plant to examine the possibility of injecting upgraded biogas produced from its operations into the Companies' distribution system.

Efforts have begun through dialogue with provincial government employees from Ministry of Energy Mines and Petroleum Resources, the Ministry of Agriculture, the Ministry of Environment, and the Premier's Technology Council to evaluate the environmental and community benefits of the development of a biogas industry in British Columbia.

While investigation into this field is preliminary, the Companies feel there may be a an opportunity to invest in several biogas projects over the next few years which would supplement the distribution systems with renewable fuels, thus displacing natural gas by the amount of biogas accepted into the distribution system.

6.9.3. NGV - Natural Gas Vehicle projects

Natural gas vehicle projects have a number of opportunities to reduce GHG emissions over conventional fuel choices and further increase energy efficiency and emission savings by utilizing liquefied natural gas in heavy-duty vehicle applications or utilizing renewables or hydrogen in combination with natural gas in specific transportation applications.

Vehicle Grants – In order to continue to promote the use of a growing variety of natural gas vehicle applications, customers that would not otherwise be eligible for grants under Rate 6 may be eligible through this fund instead. Grants for light duty vehicles are currently $1,500-$2,500 per vehicle, medium duty vehicles are $5,000 and heavy duty vehicles are $10,000. Special demonstration grants are available as well of up to $100,000 per year.

Hydrogen / Compressed Natural Gas blended projects ("HCNG") - Unlike conventional Compressed Natural Gas ("CNG") vehicles, new technology is emerging whereby hydrogen is blended at the pump with compressed natural gas: a 20% blend of hydrogen is added to the fuel. The mix is then dispensed into a tank on the vehicle and the 80/20 blend is burned in a standard natural gas engine. TransLink has a demonstration project underway with 4 buses utilizing this blend. HCNG is one of the most promising near-term opportunities for utilizing hydrogen in vehicles and moving towards a more hydrogen driven economy. As hydrogen burns cleaner than natural gas, further emission reductions are gained and 10-20 % GHG reductions over CNG can be achieved. Other HCNG initiatives may include fuel for trains, fleets and other vehicle applications.

The Companies see participation in this field as a viable opportunity to promote cleaner natural gas vehicles and projects would be reviewed on an individual basis.

Biogas vehicles - Biogas as explained above is the capture of methane from organic waste. This methane can be cleaned up and utilized in several different ways, one of them being as a vehicle fuel. The emission reductions from such initiatives can be significant.

6.9.4. Stationary Power Generation

There are several new stationary power generation projects underway whereby natural gas is used as the feedstock to provide heat and power to homes, ships and other commercial buildings. As mentioned above, the Terasen Utilities are keeping a close eye on this industry and foresee the potential for participation in this field. Funding would only be allocated to this initiative if further potential developed.

6.9.5. Measurement

Residential

The target market for real-time energy consumption would be multi-family complexes such as town-houses, row-houses and high-rise multi unit buildings.

Real-time energy consumption measurement - Real-time energy consumption metering can be an important tool in energy measurement and management. A reduction in energy use of 20-30% in multi-family developments can result from enhanced visibility and individual energy measurement with the installation of individual meters. The program objective will be to provide customers with the initial tools and data necessary to reduce energy use and increase efficiencies.

The Companies would consider providing an incentive for builders and developers of $100 per suite to install individual meters or thermal metering to cover the cost of added fittings, valves and promote the use of energy measurement.

6.9.6. Other

Other potential Innovative Technologies include natural gas powered generation for ships while in Port (to reduce or eliminate the need to idle on diesel), net zero buildings and district energy solutions using renewables.

Table 6.9.5 below shows the breakdown for expenditures in all program areas:

Table 6.9.5 - Proposed Expenditure Innovative Technologies, NGV and Measurement

Innovative Technologies, NGV and Measurement						
Utility	**Sector**	**Nature of Proposed Expenditure**	**2008**	**2009**	**2010**	**Total**
TGI	**Residential**	**Incentives**	$400,000	$400,000	$400,000	$1,200,000
TGI	**Commercial**	**Incentives**	$400,000	$400,000	$400,000	$1,200,000
TGVI	**Residential**	**Incentives**	$100,000	$100,000	$100,000	$300,000
TGVI	**Commercial**	**Incentives**	$100,000	$100,000	$100,000	$300,000
		Total	$1,000,000	$1,000,000	$1,000,000	$3,000,000

6.10. The Industrial Sector

The Companies have not included energy efficiency initiatives for industrial customers, namely those in TGI Rate Classes 22, 27 and 7 or the three TGVI transportation customers (BC Hydro, the VIGJV and TGI for Squamish), within this Application. The Companies did not originally plan for specific programs for industrial customers based upon the following:

- The Companies' industrial customers typically have diverse needs that may not be met by a generic EEC program. Individualized EEC programs may be required to meet specific customer requirements. Further, separate tariff supplements or rates approved by the Commission may be required.
- The Companies' industrial customers generally make energy efficiency decisions based largely on the economic payback. As such, it may be difficult for the Companies to provide the level of EEC financial support that would make an energy efficient decision economic to an industrial customer.
- The majority of an industrial customer's gas energy cost is the cost of commodity which is supplied by a gas marketer, not the Terasen Utilities. Further, because industrial customers pay market rates for commodity, they make energy decisions, including fuel switching, based upon the price of commodity. Increases in gas commodity prices have resulted in many customers switching to other fuel types; energy efficiency is not the main driver for this action.
- The Terasen Utilities had not received significant demand from industrial customers for such initiatives.

However, at a recent workshop the Companies had inquiries from stakeholders about the possibility for EEC programs for industrial customers. Further, with the release of the 2007 Energy Plan and the introduction of the carbon tax, the Company believes that there is a greater need for industrial EEC programs. At this stage, the Companies believe that some potential areas of activity in the industrial sector are individual customer CPRs at large industrial sites, equipment-specific feasibility studies, and measurement and contributions to efficiency improvements for lumber kilns.

In the event that the Application is approved, the Terasen Utilities intend to establish an industrial customer EEC working group and convene in Q3 2008 to determine the need for industrial EEC programs, the type of programs that would be beneficial to the industrial customer base, and the funding required in support such programs. Should the results of the working group indicate that programs and expenditures are warranted, and the Companies are supportive of the programs and expenditures, the Companies would submit a report and request for additional funding and approval as part of the TGI Annual Review and TGVI Settlement Update in Q4 2009.

6.11. Staffing

Implicit in increased Energy Efficiency and Conservation activity will be a need for an increase in staffing at Terasen Gas. Costs associated with staffing for programs have been included in Program Costs for each measure, and are incremental requirements by program. Program and incentives are broken down in Table 6.1a in Section 6. These staffing costs are included in the $56.6 million for EEC expenditures for which approval is being sought in this Application. The required total person years ("py") to support the EEC programs proposed in this Application are summarized in Table 6.11, by year:

Table 6.11 - Proposed EEC Staffing Levels, in Person Years, by Year

	2008 (py)	2009 (py)	2010 (py)	Total (py)
Program Development	1.6	0	0	1.6
Program Operations	9.6	12.9	16.5	39.1
Evaluation	0.8	0.1	5.2	6.0
Total Staffing	12.0	13.0	21.7	46.7

The Terasen Utilities currently has a core Energy Efficiency and Marketing staff of four. Support for the Terasen Utilities current DSM activity is provided by the Technical Sales Support staff (four staff), the Commercial and Industrial Account Management team (eight staff), and the Residential New Construction Account Management team (eleven staff), on a part-time, as-needed basis. The Companies anticipate increasing core staffing as well as using the resources of outside consultants where appropriate to design, implement, deploy and manage the EEC activity outlined in this Application. This Application contains a request for funding to 2010. The Companies anticipate filing an Application for activity post-2010 during that year, so presumably would have an ongoing need for a certain level of DSM staffing.

6.12. Financial Treatment for Energy Efficiency and Conservation Expenditures

This section discusses the financial treatment of EEC expenditures.

Current Regulatory Accounting

As discussed in Section 3, for TGI, program costs are currently recorded as O&M, and incentives and rebates are charged to a regulatory asset deferral account and amortized over three years. For TGVI, program costs are recorded as O&M and incentives and rebates are charged to a regulatory asset deferral account and amortized over one year. The Companies propose to treat the incremental EEC expenditures above amounts already approved as part of TG PBR Extended Settlement and TGVI RR Extended Settlement as capital.

Regulatory Accounting For Incremental EEC Expenditures

The Terasen Utilities propose that the incremental EEC expenditures and existing incentive amounts in TG PBR Extended Settlement and TGVI RR Extended Settlement (TG - $1.5 million and TGVI - $.650 million) be treated in the same manner by charging them to a regulatory asset deferral account on a tax-adjusted basis, the balance of which is amortized over twenty years, with amortization commencing the year following the year in which the expenditure is made. Proposed EEC expenditures will be recovered from the customers of each utility based on the expenditures incurred by each utility. Allocations of costs to customer classes will be done in a manner consistent with current practice for each utility. The change in amortization period will smooth the impact to rates from the proposed increase in expenditure. The twenty year period is more representative of the benefit received by customers from the EEC expenditures resulting in appliance and energy system installations with a weighted average measurable life of 22.5 years. Many of the measures proposed have equipment lives of greater than twenty years, the Companies believe that it is reasonable to expect that the savings from the measures proposed in this Application will persist for at least twenty years, thus the twenty year amortization period was selected. BC Hydro currently amortizes DSM expenditures over a ten year period, while FortisBC amortizes DSM expenditures over the life of the measure being funded, and thus has some DSM expenditures that are amortized over thirty years.

Twenty years was selected by the Companies as being a good balance between recognizing the persistence of savings, and keeping natural gas rates competitive with other energy forms by avoiding an excessively short amortization period. Customer rate impacts are discussed further in Section 7.1. A twenty year amortization period is consistent with the Commission's guidelines regarding accounting for DSM expenditures, as per Commission Order No. G-55-95, dated June 29, 1995, that states "A utility may apply for a normal write-off longer than 10 years". It is the Companies view that the amortization period of twenty years better matches the cost recovery to the period over which benefits will accrue to customer.

Practices of Other Utilities

This financial treatment is consistent with an approach used by other utilities in British Columbia.

British Columbia's two major electric utilities, BC Hydro and FortisBC, capitalize EEC expenditures in a regulatory deferral account.[30] BC Hydro and FortisBC's DSM programs are discussed in detail in Appendix 4, "Other Utilities Detail".

Although some utilities have a DSM incentive based on energy savings targets, the Companies felt that setting such a target on which an incentive would be paid could prove to be challenging and contentious, given that the Companies have not previously established a target for energy savings from DSM expenditures. Setting a target could also be a time-consuming and costly exercise, as first a target would need to be developed and proposed by the Companies, which target would then need to be investigated and debated by stakeholders.

International Financial Reporting Standards (IFRS)

The proposed financial treatment of EEC expenditures is currently permitted under Canadian Institute of Chartered Accountants ("CICA") Handbook section 3062 "Goodwill and Other

[30] Prior to early 2008, the funding of BC Hydro's capital expenditures (including capitalized Power Smart DSM spending) for revenue requirement purposes was considered to be 100% debt based on the definition of equity for BC Hydro set out in Heritage Special Directions HC1 and HC2. In early 2008 the provincial government amended the definition of equity for BC Hydro by Orders-in-Council 27 and 28 dated January 17, 2008. The new equity definition includes a deemed equity component of 30% for revenue requirement purposes. This means that new capital expenditures (including capitalized Power Smart DSM spending) will now be funded by a combination of debt and equity and that BC Hydro will earn an equity return on the deemed 30% portion of capital spending.

Intangible Assets". Effective for 2009, a new CICA Handbook section 3064 "Goodwill and Intangible Assets" will replace section 3062. Under the new section, DSM expenditures are expected to continue to meet the requirements of the Handbook for deferral. Should DSM expenditures fail to meet those criteria, they would qualify for deferral in the GAAP hierarchy under the provisions of SFAS 71 "Accounting for the Effects of Certain Types of Regulation". However, the Accounting Standards Board of Canada has recently adopted the strategy of replacing Canadian Generally Accepted Accounting Practices ("GAAP") with International Financial Reporting Standards ("IFRS"). This change will be effective 2011 for all publicly accountable entities, including the Companies, and thus will not affect the expenditures incurred in 2009 and 2010. The Companies are of the view that the proposed financial treatment of EEC funding also meets the requirements of IFRS. If, however, after further discussion and closer examination in conjunction with auditors and other utilities, the EEC funding failed to pass these tests, then the Terasen Utilities will revisit the program to ensure that it continues in a fashion which maintains an alignment on interests between customers, investors and government policy.

6.13. Portfolio Approach to EEC Programs, and Alignment of Program Cost/Benefit Analysis Practices Across the Terasen Utilities

In this Application the Companies are recommending that to evaluate EEC programs the following filters apply:

a) Portfolio Approach
b) Exclude Free Riders Effect
c) Attribution.

These filters are discussed below.

Portfolio Approach

The Terasen Utilities propose that all energy efficiency and fuel switching initiatives for both TGI and TGVI be evaluated using the cost-benefit tests outlined in the "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects", which is attached as Appendix 12. The Companies propose that the EEC portfolio be evaluated on an overall combined basis, rather than on individual initiatives or program areas. That is, some individual initiatives may have a TRC test result of less than one, however the overall EEC portfolio would need to have a TRC test result of at least one.

By following this approach, the Companies would be in a position to encourage ever-increasing levels of efficiency in natural gas equipment, including that equipment which is relatively new to the market and as such, has a higher initial cost due to the fact that it has not yet reach economies of scale and therefore may have a TRC lower than 1.0. Further, usage patterns in some geographic regions may change over the program period from 2008 to 2010, resulting in TRCs of lower than 1.0 for some particular measures in some particular geographic regions. A portfolio approach to cost-benefit analysis would allow the Companies to maintain the principles of uniformity (providing the same programming to customers throughout the Companies' service territories) in instances where there may be regional differences in usage patterns may drive the TRC below 1.0 in that particular region. At this time, there are no initiatives contemplated for residential and commercial energy efficiency, and for residential fuel switching, that have a TRC of below 1.0.

This portfolio approach is consistent with the Companies' proposed approach recently approved by the Commission in the System Extension and Customer Connection Policies Review Application, where the total annual aggregate Profitability Index for Main Extension tests in a given year must be at least 1.1 or higher. The energy efficiency and fuel switching programs would be planned and evaluated on the TRC, the RIM test, the Utility Cost ("UC") test and the Participant test, and the overall portfolio TRC test results would have to be greater than 1.0 to proceed.

The Portfolio Level analysis includes the costs for the proposed investment in Conservation Education and Outreach, in Joint Initiatives, in Innovative Technologies, NGV and Measurement and in Trade Relations, but does not include any accounting for energy savings benefits from these afore-mentioned activities. In the case of Conservation Education and Outreach and Trade Relations, the Companies propose to monitor the effectiveness of these two initiatives through awareness tracking. In the case of the Conservation Education and Outreach initiative, the Companies would include a significant Advertising Tracking and Customer Research component in this communications program so as to gauge the effectiveness of both the messaging and the media being employed. In the case of Trade Relations, targeted trades groups would be surveyed annually so as to monitor the effectiveness of the Companies' outreach and training efforts with these trades groups. In both cases, the Companies would hope to develop an understanding of energy savings from these initiatives between now and 2010, with a view to including energy savings as a benefit in future analyses.

In the Joint Initiatives program area, the traditional DSM cost-benefit tests for the Affordable Housing Sector may not provide for a high enough level of financial incentive to spur efficiency upgrades. The initial comments from the Working Group for DSM for Affordable Housing that Terasen Gas is leading indicate that in order to be effective, energy efficiency programs for this sector must provide a financial incentive that covers almost the entire cost of an equipment upgrade, rather than just a portion of the increment for efficient equipment. To give a specific example, incentives for furnace upgrades for this sector may need to cover the entire cost of a new furnace rather than just a portion of the cost differential between an Energy Star furnace and a mid-efficiency furnace. The Terasen Utilities are of the view at this time, that the Companies should not act alone as a social instrument, but rather in concert with others, to establish a DSM program for Affordable Housing. Currently the Terasen Utilities anticipate that funding for such a program, over and above the amounts requested by the Companies with this Application, would be made available by Government as a matter of social policy. Alternatively, additional funding could be sought by the Companies in a separate, future application to the Commission, if the findings of the Terasen Utilities and the Working Group suggest this is a viable alternative. The Working Group for DSM for Affordable Housing that the Terasen Utilities are leading will continue to find a way to measure the costs and benefits of incentives, as well as find ways to actually deliver energy efficiency upgrades, to this unique sector.

In the case of the Innovative Technologies and Measurement components of the proposed funding (refer to Section 6.9), the relative newness of some of these technologies under consideration mean that equipment costs are high due to low market penetration. Further, good data on energy savings from deploying these new technologies in the Companies' service area may not be available due again to the relative newness of the technology. The Companies propose that programs in this area would be in the nature of pilot programs, where installations are restricted in both number and by geography, so as to give the Companies a better understanding of the costs and benefits of these newer technologies.

In the case of the Natural Gas Vehicles components of the proposed funding (refer to Section 6.9) the Companies suggest that a simple payback analysis would be appropriate, given the low penetration of these vehicles in the marketplace.

Proposal to Exclude Free Rider Effects

Table 6.13 below shows the results of the standard Demand Side Management cost-benefit tests for the proposed Residential and Commercial Energy Efficiency and Residential Fuel Switching initiatives for the Terasen Utilities, including free rider effects, as well as Portfolio level results. Free riders are customers who participate in a program, but would have undertaken the same conservation actions even if the program were not offered. The cost-benefit analysis presented in Tables 6.13 and 6.13a below includes the impact of the carbon tax on customer savings. Further detail on cost-benefit tests can be found in Appendix 11,"EEC Portfolio Cost-Benefit Results".

Table 6.13 - Cost-Benefit Results for EEC Portfolio including Free Rider Factor

	RatePayer Impact Measure	Utility	Participant	Total Resource Cost	TRC benefit
Residential Energy Efficiency	0.6	2.6	14.4	2.4	$15,048,000
Residential Fuel Subsitution	1.2	FS	0.9	2.5	$37,723,000
Commercial Energy Efficiency	0.7	3.3	8.1	3.7	$108,512,000
Portfolio Level	0.5	1.4	8.7	2.9	$139,448,000

Please note that the analysis above accounts for free rider effects, meaning that the companies have endeavored to apply a notional free ridership factor.

Although the cost-benefit test results shown above in Table 6.13 include a net-to-gross or "free ridership" factor, the Companies propose that the requirement to net out energy savings resulting from the participation of "free riders" be eliminated from the cost/benefit analyses for EEC programs in British Columbia. Table 6.13a below shows the cost-benefit test results excluding a free rider factor, where the benefits are the gross energy savings from the EEC activity.

Table 6.13a - Cost-Benefit Results for EEC Portfolio excluding Free Rider Factor

	RatePayer Impact Measure	Utility	Participant	Total Resource Cost	TRC benefit
Residential Energy Efficiency	0.6	3.5	13.7	3.1	$23,456,000
Residential Fuel Subsitution	1.2	FS	0.8	2.4	$41,648,000
Commercial Energy Efficiency	0.7	3.8	7.9	3.9	$121,880,000
Portfolio Level	0.6	1.6	8.6	3.1	$165,149,000

The proposed threshold TRC test results both increase slightly when free rider factor is excluded from the cost-benefit tests, because the savings or benefits from EEC activity are expressed as 100% of the gross energy savings from the EEC activities. The overall TRC ratio increases for the same reason.

Free rider ratios are the subject of great debate as there is no definitive method to determine the number of free riders in a program. The methodology and reporting of free riders is subjective, even when program participants are surveyed regarding a program's influence over their purchase decisions. Free rider rates are notional. Further, the net-to-gross ratio of energy savings from EEC activity is complicated by "free driver" effects. The free driver effect is very difficult to quantify, but it will tend to cancel out the free rider effect. If the goal of municipal, provincial and federal policies is to reduce energy consumption overall, programs that help to achieve these goals should be evaluated based on gross energy savings, regardless of program participant motivation. The Companies believe that if a program participant receives an incentive for undertaking an activity that results in a desirable energy outcome, it should be the outcome that matters, not the way in which it was achieved. Including, the notional effects of free riders in the cost-benefit tests serves to reduce the number of programs that can be offered and consequently reduces the overall energy savings that customers will be able to realize through EEC programs. The Companies are of the view that the inclusion of the effects of free riders in the cost-benefit test for EEC programs distorts the value of EEC programs and is counter to the objectives of the energy plan.

Attribution

It is possible, as a matter of practice regarding cost-benefit tests for DSM programs, for utilities to include savings resulting from, or attributed to the projected introduction of regulation resulting from certain EEC programs. This is a practice known as “attribution”. The cost-benefit test results that the Terasen Utilities have completed in support of its proposed slate of programs, as shown above in Tables 6.13 and 6.13a, do not include savings related to attribution. However, with this Application, the Companies seek approval to include attribution savings in its cost-benefit tests in the future, at the point in time which new regulations go into effect. Specifically the Companies propose that once a proposed regulation and implementation date for minimum efficiency standards for an appliance or building or energy system is announced by a regulating body, the Companies be permitted to attribute savings to market transformation programs for that particular appliance, building or energy system in its cost-benefit tests at that time. The attribution rates proposed by the Company, which it is seeking approval for with this Application, for any such future regulation are outlined in Table 6.13b below.

Table 6.13b - Attribution Rates

Regulation Year	Percentage of Savings Attributed to Program
1	50
2	40
3	30
4	20
5	10

Results

The Companies believe that the cost-benefit results for the proposed EEC expenditure in this Application are under-stated, because the benefits used in the calculations include free-riders, effectively reducing the net energy savings, and exclude attribution effects, as well as excluding savings from the proposed expenditure on Joint Initiatives, Trade Relations, Conservation Education and Outreach and Innovative Technologies, Measurement and NGV. However, even with this approach, which could be considered conservative, the Total Resource Cost test result for the EEC portfolio as a whole is positive, with a ratio of 2.9., and a net financial benefit of

$139.4 million. If free rider effects are excluded, as the Companies are proposing, the EEC portfolio has a TRC ratio of 3.1 and a net financial benefit of $165.1 million.

6.14. Reporting and Stakeholder Group

The Companies recognize the need for accountability for the funds approved for EEC programs. This section describes the type of reporting on EEC programs that the Companies are proposing, as well as the formation of an EEC Stakeholder Group to provide the Companies with input on EEC activity. The Terasen Utilities believe that the proposals below should provide the Commission and stakeholders with an adequate level of comfort that the funds are being well-spent.

6.14.1. Reporting

It is anticipated that the Companies' Executive Team will approve the EEC activity for the upcoming year early in that year, permitting the Companies to file an Annual EEC Report with the Commission by the end of the first quarter every year. The Report would detail program activity, expenditures, and cost-benefit results for the previous year, as well as describe program activity and provide forecasts for the upcoming year.

6.14.2. Stakeholder Group

The Companies believe that engaging an EEC stakeholder group to guide and inform the Companies' EEC activities will be a key success factor. The Companies have discussed this Application at a high level with Regulatory Stakeholders (those that have historically intervened in the Terasen Utilities' regulatory proceedings). In the event that the relief sought is granted, the Companies would form and engage an EEC stakeholder group with membership representing both TGI and TGVI from the following areas:

- Provincial and municipal governments
- Non-Governmental Organizations
- Consumer advocates, representing residential customers
- Affordable housing advocates, representing the low-income sector
- Commercial customers
- Trade organizations

- Equipment manufacturers
- Other utilities

The Companies intend to hold annual EEC workshops with stakeholders, at which the Companies would present updates on program progress. The workshops would also be a forum for stakeholder input on developing new programs and refining existing programs, as well as providing some opportunity for oversight and comment by the Stakeholders on the Companies' EEC activity. The Companies would consider consolidating the Terasen Utilities' stakeholder activity with that of other utilities and the Province, in order to avoid potential "stakeholder fatigue".

7. Customer Impacts, Benefits and Advancement of Government Energy Objectives

This Section examines how customers will benefit from EEC programs and also how this Application advances government's energy objectives.

The programs contemplated in this EEC Application are expected to provide the following outcomes:

- Provide customers access to a wider variety of energy efficiency and conservation incentive programs, assisting them to reduce energy consumption, thereby lowering customer energy bills and reducing the individual and societal impacts associated with energy use.
- Expand the range of customers for whom energy efficiency and conservation programs are available. For example, the commercial program portfolio is proposal is a significant expansion over the Companies' current efforts, and in the residential sector, funding is contemplated specifically for DSM for Affordable Housing, as outlined in the Section 6.6
- Provide education for customers and the public at large about energy and conservation issues, leading to customers making more informed choices about energy equipment and actions, as outlined in the proposal received from Wasserman and Partners, attached as Appendix 8
- Recognize the need to maintain a competitive cost for using natural gas an energy source, thus maintaining the energy balance in the province, and ensuring that customers have a wide variety of cost-competitive energy sources to choose from
- Support BC Hydro and FortisBC in achieving their conservation goals, through both incidental electrical savings from such items as efficient motors in efficient natural gas appliances, and through the residential fuel switching measures proposed herein, thus helping to minimize the need for the customers of the electric utilities to invest in additional generation and transmission infrastructure
- Recognize the continued value in adding efficient cost-effective customers to the Terasen Utilities distribution system, keeping the use of natural gas and other energy forms competitive for all customers

- Recognize that individual metering technologies can help to inform customers as to their individual consumption, which is shown to lead to reduced overall consumption of up to 30%[31], as noted in Section 7.3
- Encourage the utilization of new and alternative technologies that have not to date enjoyed strong market penetration in British Columbia
- Support the development and training of skilled tradespeople that are fluent in the merits of conservation and efficient technology

7.1. Customer Savings

The portfolio of EEC measures that the Companies contemplated in this Application will help customers use energy more efficiently and wisely. This will have the effect of reducing a customer's energy costs.

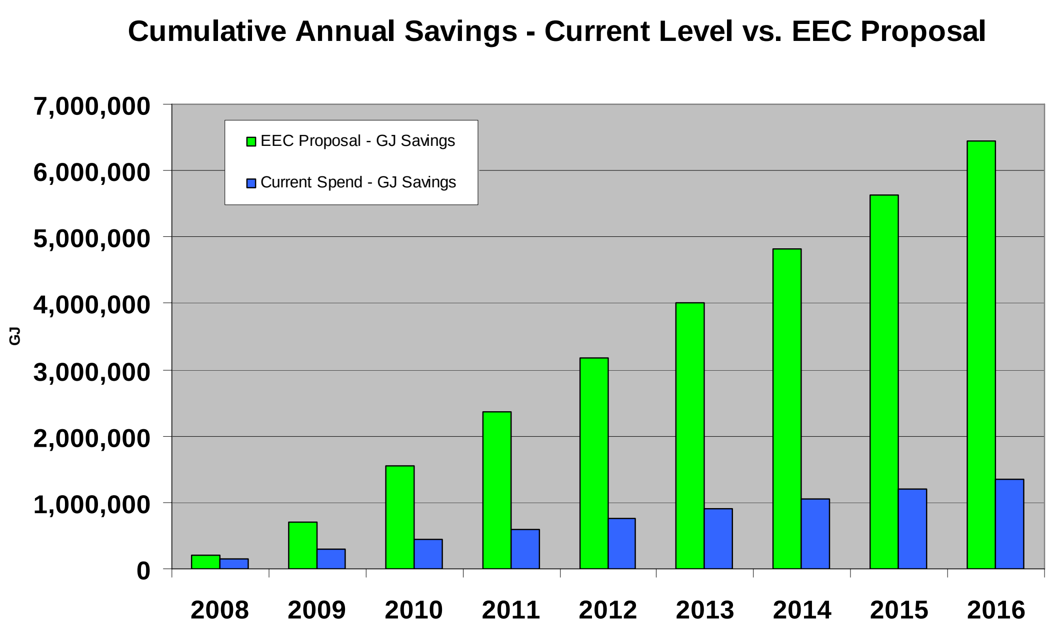
7.1.1. Expected Effect on Consumption and Associated Bill Impact

The Terasen Utilities believe that, by targeting the program areas identified in Table 1.4.1a, the energy savings from the proposed increase in expenditure and activity are likely to be significant. The estimated present value of the savings from energy efficiency is almost 10 million GJs over the lives of the various measures proposed, while the fuel switching activity being proposed is estimated to result in additional load of approximately 2.3 million GJs (present value). The anticipated net present value of the energy savings from the energy efficiency and fuel-switching activity being proposed in this Application is approximately 7.7 million GJs. This does not include potential savings arising from Conservation Education and Outreach, Joint Initiatives, or Innovative Technologies, NGV and Measurement program areas.

The increased level of EEC spending contemplated in this Application, as compared to the existing funding levels, will provide customers greater opportunities to realize energy savings. The graph below (Figure 7.1.1) suggests the magnitude of the opportunity for additional natural gas energy efficiency and conservation activity that is being foregone at the current DSM expenditure levels (figures are nominal).

[31] Article, "The installation of meters leads to permanent changes in customer behaviour", Lars Gullev and Michael Poulson, "News from DBDH", March 2006

Figure 7.1.1 - Potential Savings from Increased EEC Activity by the Terasen Utilities



This section of the Application addresses customer's rates if funding level increases are approved.

There is also a benefit associated with reduced Carbon Tax costs, which is discussed in the context of GHG emission reductions below.

7.1.2. Revenue Requirements and Rate Impacts

Below is detail information about how the funding request of an additional $40.696 million for TGI and $7.336 million for TGVI will impact revenue requirements for each utility and customers.

The TGI PBR Extended Settlement includes DSM funding totaling $3.124 million ($1.50 million for incentives and $1.624 million for expense), in each of 2008 and 2009. Similarly, TGVI RR Extended Settlement includes DSM funding totaling $1.150 million ($0.650 million for incentives and $0.500 million for expense), in each of 2008 and 2009. The respective Extended Settlements specify how these DSM related expenditures are to be included in revenue requirements and rate determinations for 2008 and 2009. The two year total (2008 plus 2009) of

DSM related expenditures for both Companies that are included in the Extended Settlements is $8.548 million ($3.124 million *2 plus $1.15 million *2). The Companies' current approved EEC expenditures are outlined in Table 7.1.2 below.

The Companies are proposing incremental EEC/DSM expenditures over three years of $40.696 million for TGI and $7.366 million for TGVI. On a combined basis, the total additional funding for the three years ending 2010 over and above the approved levels stipulated in Extended Settlements for the two years ending 2009 is $48.062 million, bringing the three year total for both Companies to $56.61 million. This information, in addition to the proposed amounts to be charged to the deferral account and O&M expense, is summarized in Table 7.1.2.1, below.

Table 7.1.2.1 – Current, Proposed, and Incremental EEC expenditures, by Utility ($000's)

	2008	2009	2010	Total
Currently Approved Expenditures				
TGI - Expense	$1.62	$1.62	$0.00	$3.25
TGI - Incentives	$1.50	$1.50	$0.00	$3.00
Total TGI	$3.12	$3.12	$0.00	$6.25
TGVI - Expense	$0.50	$0.50	$0.00	$1.00
TGVI - Incentives	$0.65	$0.65	$0.00	$1.30
Total TGVI	$1.15	$1.15	$0.00	$2.30
Combined - Expense	$2.12	$2.12	$0.00	$4.25
Combined - Incentives	$2.15	$2.15	$0.00	$4.30
Total Combined TGI & TGVI	$4.27	$4.27	$0.00	$8.55
Incremental Expenditures as proposed				
TGI - Incentives	$10.87	$12.63	$17.20	$40.70
TGVI - Incentives	$1.68	$1.89	$3.79	$7.37
Total Combined TGI & TGVI Incentives	$12.55	$14.52	$20.99	$48.06
Total Proposed EEC Expenditures				
TGI - Expense	$1.62	$1.62	$0.00	$3.25
TGI - Incentives	$12.37	$14.13	$17.20	$43.70
Total TGI	$14.00	$15.75	$17.20	$46.94
TGVI - Expense	$0.50	$0.50	$0.00	$1.00
TGVI - Incentives	$2.33	$2.54	$3.79	$8.67
Total TGVI	$2.83	$3.04	$3.79	$9.67
Combined - Expense	$2.12	$2.12	$0.00	$4.25
Combined - Incentives	$14.70	$16.67	$20.99	$52.36
Total Combined TGI & TGVI	$16.83	$18.80	$20.99	$56.61

The result of the mechanics described above based on the EEC expenditures proposed with this Application, the Companies expect that total EEC expenditures of $14.702 million ($16.826 less $1.624 less $0.500) will be added to the deferral accounts of the Terasen Utilities in 2008 on a before tax basis. For 2009, in aggregate, the Companies expect that $16.671 million ($18.795 million less $1.624 less $0.500) will be added to the deferral accounts of the Terasen Utilities on a before tax basis. The deferral accounts will be included in rate base, on an after tax basis and 2009 amortizations will equal one-twentieth of the forecast balance in the deferral account at December 31, 2008.

Terasen Gas Inc.

As part of TGI 2008 revenue requirement there is a total of $3.124 million per year for EEC activity. Over a two year time period 2008-2009 as per Extended Settlement a total of $6.248 million could be spent on EEC activity. Therefore, the incremental funding request for EEC activity over three years would be $40.696 million for TGI. Impact of this incremental funding on TGI revenue requirement is shown in Table 7.1.2.2.

Table 7.1.2.2 TGI - Impacts of Total EEC Expenditure on Annual Revenue Requirements ($000's)

2008-2020
Amortization Period 20 Years

Line No.	Particulars	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	**Current DSM**													
2	Beginning of Year Balance	$ 1,526	$ 754	$ 370	$ 17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Additions	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Tax Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Net Additions	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Amortization	(772)	(384)	(353)	(17)									
7	End of Year Balance	754	370	17	-	-	-	-	-	-	-	-	-	-
8														
9	**New EEC**													
10	Beginning of Year Balance	-	8,537	17,999	29,287	27,756	26,224	24,692	23,160	21,628	20,097	18,565	17,033	15,501
11	Additions	12,372	14,128	17,196	-	-	-	-	-	-	-	-	-	-
12	Tax Adjustment	(3,835)	(4,238)	(4,987)	-	-	-	-	-	-	-	-	-	-
13	Net Additions	8,537	9,890	12,209	-	-	-	-	-	-	-	-	-	-
14	Amortization	-	(427)	(921)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)
15	End of Year Balance	8,537	17,999	29,287	27,756	26,224	24,692	23,160	21,628	20,097	18,565	17,033	15,501	13,970
16														
17	**Total Deferred DSM**													
18	Beginning of Year Balance	1,526	9,291	18,369	29,304	27,756	26,224	24,692	23,160	21,628	20,097	18,565	17,033	15,501
19	Additions	12,372	14,128	17,196	-	-	-	-	-	-	-	-	-	-
20	Tax Adjustment	(3,835)	(4,238)	(4,987)	-	-	-	-	-	-	-	-	-	-
21	Net Additions	8,537	9,890	12,209	-	-	-	-	-	-	-	-	-	-
22	Amortization	(772)	(811)	(1,274)	(1,549)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)	(1,532)
23	End of Year Balance	9,291	18,369	29,304	27,756	26,224	24,692	23,160	21,628	20,097	18,565	17,033	15,501	13,970
26														
27	**Cost of Service**													
28	Operating & Maintenance Expense	$ 1,624	$ 1,624	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	Amortization Expense	772	811	1,274	1,549	1,532	1,532	1,532	1,532	1,532	1,532	1,532	1,532	1,532
30	Income Tax Expense	420	526	814	961	935	917	898	880	862	843	825	806	788
31	Earned Return	404	1,034	1,782	2,133	2,018	1,904	1,789	1,675	1,560	1,445	1,331	1,216	1,102
32	Total Cost of Service	$ 3,221	$ 3,995	$ 3,871	$ 4,643	$ 4,485	$ 4,352	$ 4,219	$ 4,086	$ 3,953	$ 3,820	$ 3,687	$ 3,554	$ 3,421
33	Volume (TJ/year)	139,909	141,993	143,432	145,157	146,805	148,459	150,068	151,673	153,211	154,644	155,987	157,296	158,554
34	Cost $/GJ	$0.0230	$0.0281	$0.0270	$0.0320	$0.0306	$0.0293	$0.0281	$0.0269	$0.0258	$0.0247	$0.0236	$0.0226	$0.0216

This increase in revenue requirement has the greatest impact on annual customer costs in 2011 when rates will increase by $.032/GJ. Based on a TG LML residential customer this would increase the cost per customer approximately $3.20 in 2011 based on 100 GJ of annual consumption.

Terasen Gas (Vancouver Island) Inc.

As part of TGVI 2008 revenue requirement there is a total of $1.15 million per year for EEC activity. Over a two year time period 2008-2009 as per Extended Settlement a total of $2.3 million could be spent on EEC activity. Therefore, the incremental funding request for EEC activity over three years would be $7.367 million for TGVI. Impact of this incremental funding on TGVI revenue requirement is shown in Table 7.1.2.3

Table 7.1.2.3 TGVI – Impacts of Total EEC Expenditure on Revenue Requirements ($000's)

2008-2020
Amortization Period 20 Years

Line No.	Particulars	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	**Current DSM**													
2	Beginning of Year Balance	$ 195	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Additions	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Tax Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Net Additions	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Amortization	(195)												
7	End of Year Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
8														
9	**New EEC**													
10	Beginning of Year Balance	-	1,608	3,307	5,831	5,527	5,223	4,919	4,615	4,311	4,007	3,703	3,399	3,095
11	Additions	2,330	2,543	3,793	-	-	-	-	-	-	-	-	-	-
12	Tax Adjustment	(722)	(763)	(1,100)	-	-	-	-	-	-	-	-	-	-
13	Net Additions	1,608	1,780	2,693	-	-	-	-	-	-	-	-	-	-
14	Amortization	-	(80)	(169)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
15	End of Year Balance	1,608	3,307	5,831	5,527	5,223	4,919	4,615	4,311	4,007	3,703	3,399	3,095	2,791
16														
17	**Total Deferred DSM**													
18	Beginning of Year Balance	195	1,608	3,307	5,831	5,527	5,223	4,919	4,615	4,311	4,007	3,703	3,399	3,095
19	Additions	2,330	2,543	3,793	-	-	-	-	-	-	-	-	-	-
20	Tax Adjustment	(722)	(763)	(1,100)	-	-	-	-	-	-	-	-	-	-
21	Net Additions	1,608	1,780	2,693	-	-	-	-	-	-	-	-	-	-
22	Amortization	(195)	(80)	(169)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
23	End of Year Balance	1,608	3,307	5,831	5,527	5,223	4,919	4,615	4,311	4,007	3,703	3,399	3,095	2,791
24														
27	Cost of Service													
28	Operating & Maintenance Expense	$ 500	$ 500	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	Amortization Expense	195	80	169	304	304	304	304	304	304	304	304	304	304
30	Income Tax Expense	100	66	126	190	186	182	179	175	171	168	164	160	157
31	Earned Return	67	184	342	425	402	379	356	334	311	288	266	243	220
32	Total Cost of Service	$ 862	$ 830	$ 637	$ 918	$ 892	$ 865	$ 839	$ 813	$ 786	$ 760	$ 733	$ 707	$ 681
33	Volume (TJ/year)	12,282	12,649	13,018	13,415	13,873	14,254	14,590	14,925	15,246	15,543	15,809	$ 16,053	$ 16,280
34	Cost $/GJ	$0.0702	$0.0656	$0.0489	$0.0684	$0.0643	$0.0607	$0.0575	$0.0544	$0.0516	$0.0489	$0.0464	$0.0440	$0.0418

This increase in revenue requirement has the greatest impact on customer rates in 2011 when costs will increase by approximately $0.0684/GJ. Based on a TGVI residential customer this would increase the cost per customer by approximately $4.104 in 2011 based on 60 GJ of annual consumption.

7.2. Greenhouse Gas Emission Reductions

One of “government’s energy objectives” that must be considered by the Commission in reviewing an application under section 44.2 is “to encourage public utilities to reduce greenhouse gas emissions”. The following Section discusses some of the estimated results in terms of energy and Greenhouse Gas (“GHG”) or Carbon Dioxide equivalent (“C02e”) savings anticipated from the overall portfolio of EEC activity presented in this Application.

The energy efficiency activities outlined herein will also result in a relative reduced consumption of natural gas and in some measures, electricity as well, in turn reducing GHG emissions. Since natural gas has lower associated greenhouse gas and air contaminant emissions than many other energy sources, including propane, fuel oil, transportation petroleum, and electricity created using thermal electricity generation, efficient use of natural gas in the right applications will further support British Columbia’s environmental aspirations. This Application therefore includes a request for funding to support fuel switching activity to encourage the adoption of natural gas taking the place of more environmentally detrimental alternatives. Since environmental issues have local, provincial and global implications, the Companies support an end-to-end analytic approach and conclude that using natural gas in specific end uses has a lower overall regional GHG impact than using other energies including electricity for those same end uses.

The Companies believe that the province’s GHG reduction goals are best achieved by optimally utilizing other environmentally responsible alternative energy resources, including natural gas, to avoid or defer as much new electrical load as possible and preserve existing resources for the greatest value uses. Since B.C.’s electrical grid is integrated with the larger grid in Western North America, the efficient direct end use of natural gas and other energy sources in BC results in regionally lower GHGs, as it reduces the need for electricity imports from jurisdictions where the marginal source of generation is coal or gas fired, and makes power from lower impact sources such as hydroelectric facilities available to the remainder of Western North America.

This Application includes a request for funding for fuel switching and innovative technology activities that drive change from higher-carbon fuel sources or avoid requirements for increased electricity consumption resulting in lower GHG and air contaminant emissions for the region.

Table 7.2 below details the overall natural gas, electricity and GHG savings resulting from the proposed increase in EEC expenditure.

Table 7.2 - Energy Savings by Activity by Sector by Utility

	Consumption Impact			
Sector and Activity	**Natural Gas (GJ)**	**GHG Impact (tonnes C02e)**	**Electricity (MWh)**	**GHG Impact (tonnes CO2e)**
TGI Residential Energy Efficiency	(2,087,000)	(105,790)	(41,000)	(22,550)
TGI Residential Fuel Switching	831,000	42,123	(174,000)	(95,700)
TGI Commercial Energy Efficiency	(6,858,000)	(347,632)	(511,000)	(281,050)
TGVI Residential Energy Efficiency	(181,000)	(9,175)	(4,000)	(2,200)
TGVI Residential Fuel Switching	1,446,000	73,298	(376,000)	(206,800)
TGVI Commercial Energy Efficiency	(833,000)	(42,225)	(69,000)	(37,950)
Subtotal - Energy Efficiency	**(9,959,000)**	**(504,822)**	**(625,000)**	**(343,750)**
Subtotal - Fuel Switching	**2,277,000**	**115,421**	**(550,000)**	**(302,500)**
Totals	**(7,682,000)**	**(389,401)**	**(1,175,000)**	**(646,250)**

These results reflect the present value of energy consumption impacts over the life of the measures proposed for implementation over the 2008 – 2010 timeframe. The CO2e factors that used were 0.05069 tonnes/GJ for natural gas and 550 tonnes/GWh for electricity[32]. The results do not include energy savings projections for the proposed Joint Initiatives, for the Conservation Education and Outreach funding, for the Trade Relations activity, or for savings arising from funding for Innovative Technologies, NGV and Measurement. It is clear from this table that customers would save a significant amount resulting from energy savings and avoided carbon tax impacts. A calculation, using a value of $11/GJ as the customers' avoided cost of natural gas, and the current residential electrical rate of 6.55 cents/KWh, and the proposed carbon tax on natural gas at $10/tonne is presented in Table 7.2a below.

[32] BC Hydro, 2007 Conservation Potential Review, Summary Report, Date Nov 20, 2007, page 12

Table 7.2a – Potential Customer Bill Impacts, by Activity

	Natural Gas				Electricity		
Activity Description	Consumption (GJ)	Bill Impacts	GHG Impact (tonnes C02e)	Carbon Tax Impact	Consumption (MWh)	Bill Impact	GHG Impact (tonnes CO2e)
Energy Efficiency	-9,959,000	-$109,549,000	-504,822	-$5,048,217	-625,000	-$40,937,500	-343,750
Fuel Switching	2,277,000	$25,047,000	115,421	$1,154,211	-550,000	-$36,025,000	-302,500
Totals	-7,682,000	-$84,502,000	-389,401	-$3,894,006	-1,175,000	-$76,962,500	-646,250

Using an avoided cost more reflective of marginal cost for electricity of 8.8 cents/KWh, financial savings from electricity conservation are even more significant at $103.4 million. More detail on savings resulting from specific program areas can be found in Appendix 11.

7.3. Government's Energy Objective of Promoting Demand Side Management

One of government's energy objectives under section 44.2 is the promotion of demand side measures. This Application supports government's energy objectives in several ways. Below is detailed support of how EEC this Application supports government's energy objective of promoting DSM, with reference to related Policy Actions from the BC Energy Plan from 2007.

7.3.1. Policy Action #1:

"Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020"[33]

Both the energy efficiency and fuel switching activities detailed in Section 6 support this Policy Action. Natural gas energy efficiency programs reduce customers' energy bills, making the choice of natural gas for space and water heating a more attractive option. This is important because natural gas is a more efficient fuel source for these end uses, and incenting British Columbians to install natural gas space and water heating helps to reduce BC Hydro's need for incremental electricity resources. Actively encouraging both new and existing customers to

[33] The BC Energy Plan: A Vision for Clean Energy Leadership, "Energy Conservation and Efficiency Policies", page 1

choose efficient natural gas end uses through fuel switching programs also reduces BC Hydro's need to add incremental resources.

7.3.2. Policy Action #2:

"Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia"[34]

The Terasen Utilities have enjoyed partnerships delivering incentive, education and training energy efficiency programs with BC Hydro and FortisBC, the Province, the federal government, manufacturers, industry associations, non-profit organizations and local governments. Examples would be the financial contributions made by BC Hydro and FortisBC to the Variable Speed Motor component of TGI's Energy Star Heating System upgrade program, and the Companies' participation in incentives for gas-heated homes in the BC Hydro PowerSmart New Homes Program. The Terasen Utilities have worked with the Ministry of Energy Mines and Petroleum Resources ("MEMPR") under a Contribution Agreement from the Opportunities Envelope, and at the Federal level, have enjoyed financial contributions by NRCan to various programs including the Efficient Boiler Program, the Residential New Construction Heating Program, the Switch and Save Program and the Think Grand Program. The Terasen Utilities also participate in research programs led by other utilities and by government agencies, helping to co-fund research initiatives. Furnace and boiler manufacturers have joined in the Terasen Utilities' Energy Star Heating Upgrade (for TGI) and Energy Bandit (for TGVI) programs to offer coupons to customers, piggybacking on the Companies marketing channels for these programs. TGI funds the first year of Destination Conservation, a conservation program aimed at schools and delivered by the Pacific Resource Conservation Society, a non-profit group. More funding for the initiatives outlined, and requested with this Application would allow the Companies to expand its incentive and education program efforts, in partnership with other entities offering effective joint programs.

The Companies' ability to expand joint program offerings today is limited by the available funding; current EEC funding levels for the Terasen Utilities are completely consumed by the

[34] The BC Energy Plan: A Vision for Clean Energy Leadership, "Energy Conservation and Efficiency Policies", page 2

fairly limited programs currently offered. Partnerships and coordinated efforts benefit customers by minimizing the Companies' investment in marketing, promotion and communications for programs, and by lessening the amount of market confusion by combining multiple offerings from different entities into one combined program offering aimed at a particular market segment. The Companies are actively participating in consultations being conducted by the MEMPR on coordination of energy efficiency activity in the province. However without additional funding, the Terasen Utilities would not be in a position to implement coordinated programs that are incremental to current levels of DSM activity. Examples of potential programs include appliance programs in partnership with the electric utilities so that gas customers have the same access to appliance incentives as electric customers, and participation in a potential provincial initiative to fund post-retrofit home energy audits.

One important aspect of coordination is the alignment of DSM treatments, practices and protocols across the utilities in British Columbia. With this Application, the Companies are proposing and requesting approval for a financial treatment for EEC expenditure that is more closely aligned with that used by BC Hydro and Fortis BC, namely to treat EEC expenditures as capital, by way of a Regulatory Deferral Account to be amortized over a twenty year period.

7.3.3. Policy Action #3:

"Encourage utilities to pursue cost effective and competitive demand side management opportunities"[35]

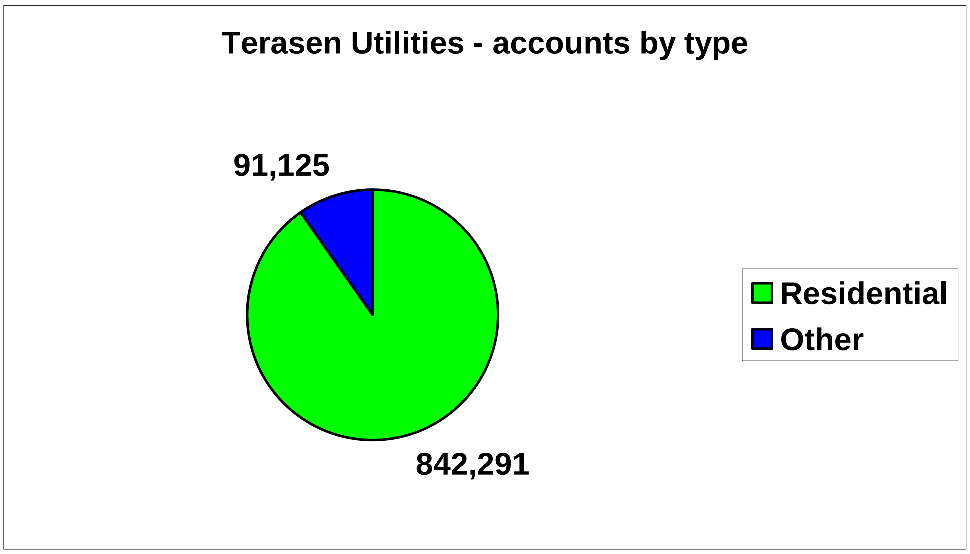
In May 2006, the Terasen Utilities received the CPR from Marbek. The goal of the CPR was to identify, at a very high level, the potential for natural gas EEC opportunities in British Columbia. In March 2007, the Terasen Utilities engaged Habart to review and refine the assumptions in the 2006 CPR, in order to arrive at a deeper understanding of both energy efficiency and fuel switching potential. The Application reflects the findings of the Habart's report, which quantified further all the cost-effective traditional DSM measures in the residential and commercial sectors available to the utility. This Application reflects a request for funding for costs for all the cost-effective measures in the Habart report. Cost-effective demand-side investments are defined in

[35] The BC Energy Plan: A Vision for Clean Energy Leadership, "Energy Conservation and Efficiency Policies", page 2

the Policy Action as "those that are equal to or lower in cost than supply side resources" and certainly both the energy efficiency and fuel switching measures delineated in the Habart report meet that criteria.

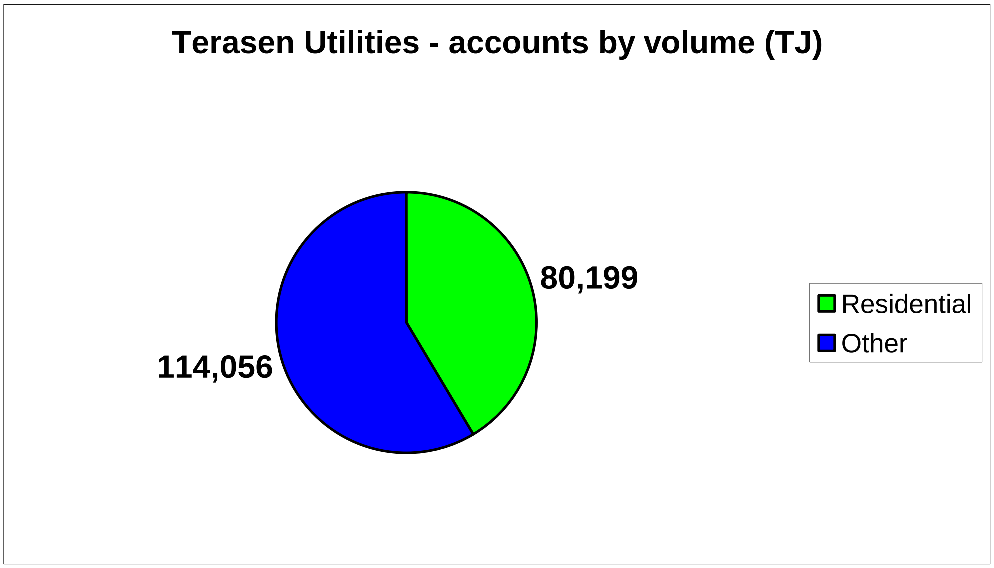
The Policy Action also encourages utilities to develop a diversified portfolio of programs, and the proposed areas of program activity in this EEC Application cover residential and commercial customers, for both retrofits and new construction. Figures 7.3 and 7.3a show gas volumes for residential and commercial customers, as well as residential and commercial customer counts.

Figure 7.3 - Number of accounts by customer type (TGI and TGVI)



Source: Application by the Companies for a CPCN for Mt. Hayes LNG Storage Facility, June 5, 2007, Appendix D – TGVI Demand Forecast Details (excluding ICP and the VIGJV), page 1-2, and Appendix E – TGI Demand Forecast Details Base Demand Scenario page 1-6

Figure 7.3a - Gas volumes by customer type (TGI and TGVI)



Source: Application by the Companies for a CPCN for Mt. Hayes LNG Storage Facility, June 5, 2007, Appendix D – TGVI Demand Forecast Details (excluding ICP and the VIGJV), page 1-2, and Appendix E – TGI Demand Forecast Details Base Demand Scenario page 1-6

While residential customers comprise the greatest number of accounts, the non-residential customers ("other" in the graphs above) comprise the greatest volume of gas consumed. It is one of the goals of this Application to increase the number of programs and initiatives available to all customers, be they residential or commercial, so that the Companies can make cost-effective DSM programs available to the greatest number of residential customers, as well as offering programs to the non-residential customer segment which could provide the greatest "bang for the buck" in terms of consumption reductions. Further, the EEC Application requests $1 million annually for "Joint Initiatives", one of which is Demand Side Management for the Affordable Housing sector. (Joint Initiatives are discussed in more detail in Section 6.2.2) The MEMPR has requested that the Terasen Utilities lead the establishment of a working group to deliver energy efficiency and conservation programs to the Affordable Housing sector, and this work is underway. A list of members in the "DSM for Affordable Housing Working Group" is attached as Appendix 7. The Working Group is focused on finding a set of common principles for the delivery of energy efficiency and conservation to Affordable Housing, and also in exploring opportunities for joint, co-funded programming for this sector. The Terasen Utilities currently do not have any funding set aside for energy efficiency and conservation for Affordable Housing as the entire existing DSM funding is consumed by existing programs. Energy efficiency and conservation for this sector would be incremental activity and therefore requires incremental funding, as requested with this Application. Continuation of the Terasen Utilities' leadership of the DSM for Affordable Housing Working Group is dependent on the Companies having approval for increased EEC expenditure in order to undertake actual programming for DSM for Affordable Housing.

The text for this Policy Action states that "…the Ministry will assess whether additional measures are needed to ensure appropriate incentives are in place to encourage investor-owned utilities to identify and pursue cost-effective DSM programs…". This EEC Application aims to encourage shareholder investment in DSM activity through capitalization of EEC funding. The proposed financial treatment is discussed in more detail in Section 6.

7.3.4. Policy Action #4:

"Explore with BC utilities new rate structures that encourage energy efficiency and conservation"36

In December 2007, the Commission issued Order No. G-152-07, a Decision on the Companies System Extension and Customer Connection Policies Review. The Commission stated that "the Commission agrees with Terasen that a situation whereby potential customers who propose to use high efficiency appliances might fail an MX test and be required to make a contribution based upon their forecast consumption, whereas they would pass the test based upon their forecast consumption using less efficient appliances, would indeed be perverse".[37] As such the Commission approved the Companies' request to incorporate a volume credit for consumption levels where customers install high efficiency space and water heating, with a further volume credit for consumption levels where new customers install high efficiency space and water heating and attain a LEED certification. However, further the Commission states that, "The proposed increases in the [Service Line Cost] allowance are more in the nature of DSM programs.[38] The Terasen Utilities are encouraged to apply for the approval for such programs in another forum, where their impact and efficiency as DSM programs can be tested." This Application constitutes such an application in that the fuel switching measures for new construction function as an inducement to customers, and builders and developers to select

[36] The BC Energy Plan: A Vision for Clean Energy Leadership, "Energy Conservation and Efficiency Policies", page 3
[37] Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. System Extension and Customer Connection Policies Review, Decision dated December 6, 2007, page 51
[38] Ibid, page 52

natural gas, much as the proposed increased Service Line Cost Allowances in the System Extension and Customer Connection Policies Review were to function as an inducement to new customers. Further, this Application includes a request for funding for "Innovative Technologies, NGV and Measurement". It is anticipated that part of this particular funding envelope could be directed to the provision of unique individual metering solutions (involving for example, diaphragm meters in mini-meter cabinets at suite entrances, or advanced meters that communicate use directly to the consumer) in multi-family dwellings that would otherwise be served with a single meter.

In TGI's Application to the Commission for "Tariff Changes to allow for Thermal Metering", dated May 8, 2007, TGI appended an article stating that "Providing individual suite metering has been shown in other jurisdictions to reduce individual consumption by up to 30%.[39] The Commission noted in Order No. G-65-07 approving the Tariff Changes to allow for Thermal Metering that, "Thermal metering has been in use in other jurisdictions, and has led to demonstrably improved energy efficiency and conservation" and that "Thermal metering is consistent with the BC Energy Plan objective of encouraging energy efficiency and conservation."[40] The Companies are hopeful that the "Innovative Technologies, NGV and Measurement" initiatives will result in increased conservation due to the increased focus on measurement, in a fashion to similar to that experienced in individual suites as referenced above.

7.3.5. Policy Action #5:

"Implement Energy Efficiency Standards for Buildings by 2010"[41]

The Terasen Utilities have identified specific areas of activity that would support this Policy Action, and that the Companies could undertake with an increase in EEC funding, such as contributing to design costs for buildings operating at 60% below the Model National Energy Code for Buildings. These specific areas of activity are outlined in more detail in Section 6 of this document.

---

[39] Article, "The installation of meters leads to permanent changes in customer behaviour", Lars Gullev and Michael Poulson, "News from DBDH", March 2006

[40] British Columbia Utilities Commission Order No. G-65-07, June 14, 2007, page 1

[41] The BC Energy Plan: A Vision for Clean Energy Leadership, "Energy Conservation and Efficiency Policies", page 3

7.3.6. Policy Action #6:

"Undertake a pilot project for energy performance labeling of homes and buildings in coordination with local and federal governments, First Nations, and industry associations"[42]

The Terasen Utilities existing DSM funding envelope does not allow for participation in new initiatives such as labeling. Labeling buildings with information about building efficiency, and the resultant energy consumption and costs is a key part of informing the public about the importance of energy conservation. As outlined in the "Joint Initiatives" discussion (Section 6.2.2), the Terasen Utilities will pursue co-funding a pilot energy performance labeling program for new and existing gas-heated homes, if this Application is approved. Labeling benefits ratepayers by providing them with a means to compare energy consumption levels between homes and is discussed further in Section 6.5, as building energy consumption labeling could be made a requirement for participation in incentive programs, particularly in new construction.

7.3.7. Policy Action #9:

"Increase the participation of local governments in the Community Action on Energy Efficiency Program and expand the First Nations and Remote Community Clean Energy Program"43

The Terasen Utilities have supported Government's Community Action on Energy Efficiency Program by participating on the program committee, and by providing funds for printing a policy manual that came out of this initiative. An increase in the EEC funding available to the Terasen Utilities will allow the Companies to commit more time towards advocating for the adoption of some of the policy tools that came out of Community Action on Energy Efficiency. As well, if the Application is approved, the Companies intend to contribute funding to the pool of monies to which Communities apply under the Community Action on Energy Efficiency, as part of the and

[42] The BC Energy Plan: A Vision for Clean Energy Leadership, "Energy Conservation and Efficiency Policies", page 4
[43] Ibid, page 6

Joint Initiatives program area described in Section 6. Participating local governments commit to reducing energy consumption in their own buildings, as well as in their communities, which in turn benefits ratepayers, partially by keeping local government energy bills and therefore property taxes down.

7.3.8. Policy Action #10:

"Ensure self-sufficiency to meet electricity needs, including insurance"[44]

Both the natural gas energy efficiency and fuel switching activities outlined in Section 6 in this Application will reduce the additional resources that BC Hydro would otherwise have to procure in the future, due to electrical efficiency co-benefits (generally motors and fans) from the installation of efficient natural gas equipment, as well as by avoiding suboptimal electrical load from heat, hot water, cooking and clothes drying. These fuel switching activities were derived from the CPR and are based upon programs that would be administered by the Companies. The CPR recently conducted by BC Hydro found that while there was significant economic potential for fuel switching, there was no achievable potential for BC Hydro PowerSmart to engage in fuel switching programs, given BC Hydro's Power Smart program guidelines. The economic potential of fuel switching in the BC Hydro CPR was found to be 24.02 PJ equivalent (6,674 GWh/year) by 2026 in the current gas supply cost scenario, and 11.85 PJ equivalent (3,293 GWh/year) by 2026 in the high gas supply cost scenario.[45] The energy efficiency and fuel switching activities covering the time period 2008 to 2010 for which funding is being requested in this Application are anticipated to result in 1,174 GWh of reduced electrical load.

Almost all of the natural gas that is consumed in British Columbia comes from British Columbia, and the Province is a net exporter of natural gas. As noted in the BCUC's Order G-152-07 dated December 6, 2007, on Terasen Gas's System Extension and Customer Connection Policies Review:

[44] The BC Energy Plan: A Vision for Clean Energy Leadership, "Electricity Policies", page 1
[45] BC Hydro 2007 Conservation Potential Review Summary Report, Marbek Resource Consultants Ltd., November 2007, p. 45

"The Commission Panel continues to agree with Terasen that the use of natural gas (as opposed to electricity) for space and water heating in BC will make additional energy available to displace coal or gas-fired generation at the margin in the Pacific Northwest."

The Decision notes further that:

"The Commission Panel does not, however, consider that it is the role of the Commission to determine governmental policy in respect of fuel choice for residential space and water heating. The Commission Panel is of the view that BC Hydro and Terasen must resolve with the Provincial Government any "ambiguity" they perceive in the 2007 Energy Plan. Accordingly, the Commission Panel makes no determinations in this regard."

The Commission further states that:

"the public interest can be served by an environment in which customers in the province have the right to choose their fuel source; in which the cost consequences of their choice are transparent; and where rate design does not hinder that choice."[46]

In the absence of specific government policy, the Companies believe that the Terasen Utilities are acting in the best interests of customers, both existing and new, by encouraging the use of efficient natural gas appliances. Energy efficiency programs assist existing customers by helping them to manage energy bills, making natural gas an attractive energy choice, keeping existing customers attached to the system thus maximizing the efficient use of the Companies' assets.

The Companies believe that encouraging natural gas energy efficiency and fuel switching activities support transparent consumer information and therefore helping customers to make the optimal decision on fuel source. As noted in the response to BC Hydro IR No. 1, Question 1 of the Companies' System Extension and Customer Connection Policies Review Application, "Terasen does not agree with the statement that the use of natural gas to provide space and water heating will result in higher greenhouse gas emissions". Consumers that are encouraged to choose natural gas for space and water heating, and for cooking and clothes drying, are likely to cause lower GHG impacts than those consumers that choose electricity for these end uses.

[46] Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. System Extension and Customer Connection Policies Review, Decision dated December 6, 2007

In the final argument to the Companies' System Extension and Customer Connection Policies Review Application Section 27 the Companies state:

> *"The electrical grid in British Columbia is not an island. British Columbia is not isolated from the remainder of the grid in North America; the grid is interconnected and a significant portion of both current and new electrical generation in western North America is from the inefficient combustion of one form or energy – coal or natural gas – to create another form of energy – electricity. For so long as coal or gas fired electrical generation continues to be the marginal source of electrical generation in western North America, the use of gas for space and water heating will "make additional energy available to displace coal or gas fired generation at the margin in the Pacific Northwest". Given that production of electricity by coal and gas fired generation is less efficient than using gas for space and water heating, GHG emission will be reduced if customers use gas rather than electricity for space and water heating."*

The Companies consider that information concerning comparative GHGs as well as general conservation messaging to support the creation of a "culture of conservation" in the province would likely be part of the information provided not only to program participants, but also as part of the larger Conservation Education and Outreach initiative, outlined in Section 6.5 of the Application, and in the proposal for Conservation Education and Outreach from Wasserman and Partners, attached as Appendix 8.

The cost consequences for consumers that choose electricity and other forms of energy over natural gas are not transparent today. This is especially true in the case of space heating, where electric baseboard heaters can be installed relatively inexpensively compared to a natural gas forced air or hydronic system, but will generate higher annual energy costs per unit than would a high efficiency natural gas heating system. The funding for fuel switching activity that the Companies are proposing in this Application would help to address the disparity in capital costs between natural gas and electrical equipment, so as to encourage more customers to choose efficient natural gas appliances over their electric equivalents which would also have the effect of lowering regional GHGs.

7.3.9. Policy Actions 29, 30, 31, 34 and 35 regarding Alternative Energy[47]

The Terasen Utilities propose to make a portion of the funding requested in this Application available to programs demonstrating and promoting innovative low-carbon technologies that provide greater expected benefits than natural gas for certain uses or under certain circumstances, but face some economic or educational hurdle. The Companies recognize that there are new, innovative non-gas technologies available such as solar hot water pre-heating, that can reduce fossil fuel consumption, and support government's policy goals, and are therefore requesting funding specifically for Innovative Technologies, NGV and Measurement. Potential programs for this funding are discussed in more detail in Section 6.9 of this document.

7.3.10. Policy Actions regarding Skills Training and Labour Policies[48]

In order to be successful in implementing an expanded natural gas EEC program, the support and training of those that actually install natural gas equipment is crucial. Therefore, with increased EEC funding, the Companies would look to increase trade relations and trades training activity on efficient gas equipment and the optimal operation of energy efficient buildings. Trades people are often the primary interface with customers at the time that the customer makes a purchase decision and the information that they provide to the customer can influence whether a customer buys a high-efficiency appliance or a standard efficiency appliance. It is therefore important that the Companies educate trades people on the benefits of high-efficiency equipment. High-efficiency natural gas equipment can be more complex to install than standard efficiency equipment, therefore training of trades people on equipment is needed to ensure that equipment is installed safely and according to design. Building operations are a key component in reducing energy consumption and GHG emissions; if a building has been designed to be efficient but is not being operated as it was designed, many or even all the benefits of that efficient design are lost. Building operators are key players in the success of any energy efficiency program. Benefits to ratepayers from an increased investment

[47] The BC Energy Plan, A Vision for Clean Energy Leadership, "Alternative Energy Policies", pages 1 - 4

[48] The BC Energy Plan, A Vision for Clean Energy Leadership, "Skills, Training and Labour Policies, pages 2 and 3

by the Companies in trade relations and training would include more accurate information received from contractors, and greater confidence that equipment is being installed as it should be, and that buildings will be operated as they were designed. An additional benefit to the province as a whole would be a more trained and skilled workforce in the field of installing efficient equipment, which will in turn support the Province's Energy Efficient Buildings initiative.

If this Application is approved, the Terasen Utilities will increase its staffing levels to design, implement and evaluate the expanded energy efficiency and conservation program. The incremental costs associated with this staffing requirement is included in the total funding request of $56.6 million as described elsewhere in this Application. As outlined in the Habart report attached as Appendix 9, the level of funding requested necessitates a total staff level of 12 in 2008, 13 in 2009 and about 21 in 2010. Currently the Companies have 4 staff members spending about 60% of their time on Energy Efficiency and Conservation Activity. Hiring and training these additional staff will also increase the number of skilled energy efficiency practitioners in British Columbia. More detail on staffing levels included in this Application can be found in Section 6.11, "Staffing".

4.4.2 ACTIVE PROGRAMS

4.4.2.1 Efficient Boiler Program

4.4.2.1.1 Program Overview

Efficient Boiler Program	
Market	New Construction / Retrofit
Duration	FEI: 2005 – Dec 31, 2011 FEVI: 2005 – Dec 31, 2011
Incentive	Purchase price incentives (rebates): • Near-condensing boilers: $4,000 per boiler plus $3 per MBH plant input; and • Condensing boilers: $6,000 per boiler plus $9 per MBH plant input. For new construction participants the program offers: 1. A maximum incentive payment (calculated as noted above) of up to 75% of the incremental purchase price of higher efficiency boilers. The purchase price of a standard-efficiency boiler is estimated using $7 per MBH of input; and 2. An incentive payment of 50% of a consultant's fees to a maximum $1,500 to offset the cost of analyzing the annual gas usage for space heating using a standard-efficiency boiler system versus a higher efficiency boiler system. For retrofit participants the program offers: A maximum incentive payment (calculated as noted above) of up to 50% of the incremental purchase price of higher efficiency boilers. The purchase price of a standard-efficiency boiler is estimated using $7 per MBH of input; 1. An incentive payment of $400 to help offset the cost of engaging a contractor to accurately estimate the peak space-heating load; 2. Where stainless steel venting is installed, an incentive of 50% of the cost up to $2,000; and 3. For participants who so choose, a monitoring incentive of $1,500 plus $1 per GJ of energy saved for closely monitoring and reporting on boiler operation and efficiency during the first year of operation.
Partner	None
Overview	
Background	Approximately 60% of commercial gas consumption in BC is used for space heating. High efficiency boiler technology, when used as part of a properly designed heating system, generates significant annual energy savings over a comparatively long estimated measure life. In fact, high efficiency boilers represent one of the most significant sources of achievable savings for the commercial sector in BC[22]. Fully 19% of such savings is attributable to high efficiency boilers. Minimum required boiler efficiencies are regulated within the province by the British Columbia Energy Efficiency Act and the Energy Efficiency Standards Regulation. Similarly, minimum boiler efficiencies are regulated in Canada as a whole by the

[22] FortisBC 2010 Conservation Potential Review, Commercial Sector Report, Marbek Resource Consultants, 2011, pg 55.

	federal Energy Efficiency Act. These acts regulate products manufactured in or imported to Canada and BC for domestic sale. Current regulation generally requires boilers to have a minimum efficiency of 80%. A proposed amendment to Canada's energy efficiency regulations would see the minimum required combustion efficiency of large boilers climb to 90% over the same period. The Efficient Boiler program is helping ease implementation of this proposed regulation by familiarizing market participants with high efficiency technology prior to the implementation of more stringent regulation.
Description	In operation since 2005, the Efficient Boiler program is FEI and FEVI's flagship Commercial Energy Efficiency program aimed at reducing gas consumption associated with space heating. By encouraging the use of high efficiency boilers, the Efficient Boiler program directly targets the commercial sector's most significant source of gas consumption (space heating) via one of its most widely used and longest lasting gas burning appliances (boilers). Installing such boilers today has a lasting impact by reducing gas consumption now, while paving the way for market transformation and ultimately more stringent regulation of commercial boilers.
Goals	• Reduce commercial sector gas consumption by encouraging the installation and use of high as opposed to standard efficiency boilers for space heating. • Increase year over year participation rates in view of maximizing gas savings. • Educate medium to large commercial customers about the advantages of high efficiency boilers and provide an incentive to facilitate the purchase of high efficiency technology. Support and prepare the way for any provincial or federal regulation requiring increased boiler efficiency. • Advance the level of skill, capacity, and understanding within trades/mechanical contractors on the correct installation practices and requirements of modern high efficiency commercial boilers. • Maintain a program TRC score greater than 1.0 and optimize the proportion of incentives over administration and marketing costs.
Implementation	
Administration	Program administration is handled entirely in-house by the Companies' EEC Staff. Shifting program administration to an outside service provider or dedicated program operations personnel is a requirement in 2011 in order to free up internal resources to be redirected towards new commercial program development and roll out.
Communications	• www.fortisbc.com – All program information, application forms, and program terms and conditions were maintained on the Efficient Boiler program webpage. • Commercial customer outreach initiative that saw the Companies call over 80,000 commercial customers to provide information on the Efficient Boiler program, among others. • Advertisements in American Society of Heating Refrigeration and Air Conditioning Engineers (ASHRAE) newsletters and the Association of Professional Engineers and Geoscientists of British Columbia's ("APEGBC") magazine. • Stakeholder focus group/feedback session in June 2010 with suppliers, contractors, engineers, participants and potential customers, energy managers, and safety officials. • Speaking engagements / presentations describing the program at events such as: BC Apartment Owners and Managers Association semi-annual tradeshows, Rental Owners and Managers Society of BC tradeshow, NRCan "Spot the

	energy savings" workshop on Vancouver Island, BC Hydro PowerSmart forum, BC Hydro energy managers training session, FortisBC energy specialist training session, Vancouver Home Show, Union of BC Municipalities Whistler 2010, Business Improvement Association meetings in Victoria, Kamloops, and Kelowna, and Council of Education Facilities Planners International conference. • Tradeshow booth/presence at: BC Agriculture tradeshow, BC Food and Restaurant Association tradeshow, Buildex tradeshow, BC Apartment Owners and Managers Association semi-annual general tradeshows, and Rental Owners and Managers Society of BC tradeshow. • Program brochures describing the program specifics and how to apply were handed out at the presentations and tradeshows mentioned above. • Information distributed to all customer touch points including call centres, sales and service staff, and commercial account managers.
Evaluation Strategy	In 2010 the Companies: 1. Completed a focus group session with program stakeholders to find out how various stakeholder groups view the program and to seek input on a revised program structure aimed at better serving stakeholder interests; and 2. Began an evaluation study (performed by a third party consultant) of natural gas savings using actual metered data and statistical methods to better quantify the savings of the program. These two initiatives will serve as an evaluation of the Efficient Boiler program from both the quantitative and qualitative perspectives.

4.4.2.1.2 2010 Efficient Boiler Program Results

With a solid net benefit-to-cost ratio, high efficiency boilers continue to generate a respectable TRC ratio of 1.4. Given a 58 percent increase in participation versus 2009, the Efficient Boiler program has ramped up its presence in the market and delivered significant natural gas and GHG emissions savings in 2010, as indicated in Table 4-5 below

Table 4-5: Efficient Boiler Program Actuals

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
New Const	FEI	3	74	1	2,630	27,055	18%	1.6
	FEVI	1	6	1	103	1,097	18%	1.3
Retrofit	FEI	88	1,189	23	36,802	378,622	18%	1.4
	FEVI	8	97	5	2,919	29,642	18%	1.2
	TOTALS	100	1,367	30	42,453	436,416	18%	1.4

In 2010, a record number of customers applied to the Efficient Boiler program, choosing high efficiency boilers over standard models. The program significantly outperformed expectations in this regard. As of the writing of this report, the program had officially recorded 100 approved participants with another 15 pending a review of their submitted documentation. By comparison, 2009 saw only 67 applicants in total, 63 of which were accepted into the program as approved participants. The next closest year in terms of participation was 2006, which saw a total of 100 applications received. The Companies believe the increased participation is a result of sustained efforts at promoting both the program itself and the Energy Efficiency and Conservation project more generally, at all available opportunities. The Companies also believe stability and consistency in the program offering (i.e. staying in market over the long term) contributes significantly to encouraging adoption of the high efficiency alternative. The decision to purchase high efficiency boilers is much influenced when the market's awareness of the program is reinforced by its time in market, and when the accepted view of the program is as a reliable source of incentives for high efficiency options.

As indicated in the "Background" section of the Table above, new efficiency regulations are currently being considered by the Government of Canada (Natural Resources Canada). The proposed regulation would see the required minimum efficiency standard of larger gas fired boilers rise from 80 percent to 90 percent by 2018. Successful installation and commissioning of high efficiency boilers requires a knowledge level beyond that of standard efficiency boilers. The Companies believe the program sends a strong signal to the market that the selection of high efficiency options should be adopted as standard practice. By encouraging the installation of high efficiency boilers today, the program is contributing to the development of the required knowledge and capacity within the market, significantly easing the implementation of new regulation over the coming years.

By year end, the efficient boiler program had committed to pay as much as $1,367,000 (not including pending applications) to participants who successfully complete their boiler installation within one year of submitting their program application. This exceeds the previous largest ever annual commitment of $1,075,455 from 2006. As in 2009, the objective moving forward is to build upon the current market momentum and the relationships that have been built with market participants to drive the rate of participation in the program in order to maximize commercial sector gas savings.

When total program spending is compared to the avoided cost of the gas, the program turns in a respectable TRC ratio of 1.4. With the free rider rate estimated to be approximately 18 percent, the annual net energy savings derived from the program's 2010 participants is over 42,000 GJs, or over 2,000 tons of GHG emissions reductions. This represents a volume of gas equivalent to the annual consumption of approximately 450 typical single family homes.

That said, room for improvement in the program remains. While the program largely met its objectives for participation on Vancouver Island, participants from the new construction market remain sparse. According to the available Major Projects Inventory quarterly publications, the value of building permits remains well below the peak activity level observed in 2007 and 2008, indicating new construction activity remained generally subdued in 2010. Still, 55 projects of $15 million or more completed construction between January and September, while 65 began construction. Having garnered only nine new construction participants in 2010, it seems evident that raising the program's profile and generating participation in the new construction market remains a priority. This is despite the Companies' efforts at promoting the program to design professionals via advertisements in both ASHRAE BC and APEGBC's regular publications. More work at promoting the program to decision makers in the new construction marketplace is a must. The Companies' new energy solutions manager positions (see Section 11) will play a central role in this effort by communicating directly with design professionals around the province. The Companies also still believe there is room for participation growth on Vancouver Island and maintaining promotional activity on the Island is critical to developing momentum and uptake.

4.4.2.1.3 2011 Efficient Boiler Program Performance Forecast

No significant changes to the cost benefit relationship of high efficiency boilers are foreseen, thus the Companies anticipate the program will continue to generate a TRC ratio of approximately 1.4. The Companies further expect the Efficient Boiler program to build incrementally upon its 2010 participation as reflected in the table below.

Table 4-6: Efficient Boiler Program Forecast

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
New Const	FEI	8	197	2	7,013	73,434	18%	1.6
	FEVI	2	12	1	205	2,190	18%	1.2
Retrofit	FEI	97	1,308	25	40,482	424,785	18%	1.4
	FEVI	9	107	6	3,211	35,091	18%	1.4
	TOTALS	116	1,625	35	50,911	535,500	18%	1.4

Two key initiatives were undertaken in 2010 that will guide activity around the Efficient Boiler program in 2011. First, in June 2010 the Companies conducted a stakeholder focus group to help raise awareness of the program and provide needed and direct insight from industry participants on the program's structure and operation. Second, in September 2010 the Companies began an in-depth, quantitative evaluation study of the program's performance in reducing natural gas consumption. The initial results suggest the natural gas savings are very much in line with what the Companies are currently claiming (approximately 15 percent reduction). The findings of these two initiatives will be used to restructure the program's processes, verify the savings assumptions, and readjust the incentive levels if the cost benefit analysis allows.

As a result of this work and experience gained throughout 2010, the Companies are undertaking revisions to the Efficient Boiler program with program elements designed to focus on three distinct markets:

1. Simple retrofits and new construction;
2. Detailed complex retrofits and new construction; and
3. Operations and maintenance.

The first program element, targeting simple retrofits and new construction, is expected to be operational in 2011. Based on feedback from program participants, this component of the program seeks to

- Make the incentives clear and straightforward to simplify the purchase decision; and
- Reduce the program's administrative burden / overhead for the Companies.

The second and third program elements, focusing on more detailed system design and boiler plant operations and maintenance, will likely be operational in 2012.

In addition, the program will expand the end uses that are eligible for an incentive. Currently, the program only provides incentives for boilers used for space heating. Different end uses are precluded from incentives due to the difficulty in establishing reasonable natural gas savings estimates. Commercial pool and water heating, however, may reasonably be included for incentives moving forward. Commercial pool heating, in particular, is a significant and unaddressed consumer of natural gas and, especially in the case of municipalities, represents an area where program incentive money can make a tangible difference to energy consumption and GHG emissions

It is believed these proposed changes, combined with sustained promotion of the program, will allow the Companies to further the penetration of high efficiency boiler technology in both the retrofit and new construction markets by making the program more visible and accessible to potential participants. Increasing the program's participant numbers furthers the Companies' goal of reducing the commercial sector's gas consumption and bringing about market transformation.

At present, participation is forecasted to grow at a reasonable 10 percent for the key FEI retrofit market; however, the Companies believe additional growth can be expected in the new construction and Vancouver Island markets. Central to this will be the role played by the Companies' new energy solutions managers. The energy solutions managers will be increasing awareness of and participation in Energy Efficiency and Conservation programs by actively participating in industry associations, hosting workshops for commercial customers and seminars for energy managers, and educating small commercial customers through the Service Line newsletter. They will also work one-on-one with current and future commercial customers to increase participation and ease the program's application process.

4.4.2.1.4 Efficient Boiler Program Summary

The Efficient Boiler program effectively encourages program participants to adopt high efficiency boilers in a market where standard efficiency alternatives remain prevalent. The program is helping pave the way for more stringent regulation by encouraging the market to develop the required competency and capacity to deal with high efficiency boilers now. Incremental increases in participation, in conjunction with the benefits derived from a program overhaul, will add significantly to the natural gas savings and dollar investment potential of the program by making it more accessible to a broader range of market participants.

awareness of and participation in Energy Efficiency and Conservation programs by actively participating in industry associations, hosting workshops for commercial customers and seminars for energy managers, and educating small commercial customers through the Service Line newsletter. They will also work one-on-one with current and future commercial customers to increase participation and ease the programs application process.

4.4.2.4.4 Energy Assessment Program Summary

The Companies believe the Energy Assessment program is a valuable tool that is, and continues to be, used to foster an awareness of energy use and energy efficiency issues among commercial customers, raise awareness of and participation in other incentive programs, and effectively encourages participants to reduce energy consumption. As such, the program remains an important component in helping to lay the foundation for longer term market transformation.

4.4.2.5 Public Sector Energy Conservation Agreement ("PSECA") Initiative

4.4.2.5.1 Program Overview

Public Sector Energy Conservation Agreement ("PSECA") Initiative	
Market	Public Sector Retrofit
Duration	FEI: Jul, 2010 – Jul, 2012 FEVI: Jul, 2010 – Jul, 2012
Incentive	The Companies made use of several existing funding models to provide incentives tailored to each project's specific situation, with all incentives falling under the umbrella of the PSECA initiative. Thus, while incentives where determined using the most appropriate program model, participants are counted under the PSECA initiative, not in the programs whose funding model was applied. Refer to: Efficient Boiler Program Efficient Commercial Water Heater Program Commercial Custom Design Program
Partner	Ministry of Environment, BC Hydro, Solar BC

Overview	
Background	The first PSECA was created in 2007 as a partnership between BC Hydro and the Government of BC. Budget 2008 committed $75 million over three years to help public sector organizations reduce provincial GHG emissions, energy consumption, and operating costs, as well as support government in achieving its goal of carbon neutrality. The first two rounds of PSECA's have achieved annual energy cost savings of close to $7.4 million, GHG emissions reductions of over 18,700 tons, and conservation of 38.6 GWh of electricity. The latest iteration of PSECA is the third round and marks the first time the Companies have been involved. Eligible public sector organizations include all organizations listed in the Government Reporting Entity ("GRE"): • Ministries and agencies; • Boards of Education; • Universities and colleges; • Health authorities; and • Crown corporations.
Description	In 2010, the Companies participated in the Public Sector Energy Conservation Agreement, operated by the Climate Action Secretariat, a division of the Ministry of Environment. The PSECA initiative represents a major undertaking for the commercial program area staff during the second half of 2010. The Companies worked in partnership with the Climate Action Secretariat, BC Hydro, and Solar BC to encourage public sector organizations to reduce energy consumption and GHG emissions by offering incentives for the completion of qualifying projects. Typical projects included: • Boiler upgrades; • Building automation controls; • Water heater upgrades; and • Heat recovery measures.
Goals	• To contribute to the Province's objective of a 33% reduction in GHG emissions from 2007 levels by 2020. • To encourage public sector organizations to reduce natural gas consumption.
Implementation	
Administration	Administration was primarily handled in-house by FortisBC staff, including receipt and review of energy studies and communication with the Climate Action Secretariat and program partner BC Hydro.
Communications	External communications were managed by the provincial government. Refer to http://www.env.gov.bc.ca/cas/mitigation/pseca.html.
Evaluation Strategy	All projects are reviewed both before and after completion. Initially, the Companies reviewed all submitted energy studies to assess the validity of the claimed natural gas savings. On completion of a project, the participant must submit the required installation documentation. Prior to paying the incentive, the Companies perform an on-site audit of all projects to ensure equipment has been installed and is functioning

	as initially proposed. At the Companies' discretion, some projects may be subjected to a measurement and verification ("M&V") protocol, whereby metering equipment is installed to measure and verify the energy savings.

4.4.2.5.2 2010 PSECA Initiative Results

The Companies' involvement with the Public Sector Energy Conservation Agreement afforded an excellent opportunity to invest in high quality, long term energy saving measures, as well as demonstrate the leverage advantage of working with partners. While the effort consumed much time that would otherwise have been devoted to new program development and roll out, the trade-off generated a program with a TRC score of 2.3 for incentive dollars committed in 2010. Program results for 2010 are provided in the table below.

Table 4-13: PSECA Initiative Program Actuals

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
New Const	FEI	-	-		-		-	
	FEVI	-	-		-		-	
Retrofit	FEI	15	531	11	18,222	163,420	0%	2.4
	FEVI	13	297	5	11,706	107,935	0%	2.2
	TOTALS	28	827	15	29,928	271,355	0%	2.3

As noted above, the PSECA initiative represents a major undertaking during the second half of 2010. The Companies believe, however, that the results to date were well worth the effort. By the end of the year the Companies committed to providing nearly $830,000 for energy saving measures at 28 locations to program participants who successfully complete the approved measures. When complete, these measures are expected to reduce natural gas consumption by approximately 30,000 GJ/yr, or enough to provide natural gas to 315 single family homes during the same time period.

The TRC score for the PSECA initiative is quite robust, which the Companies take as an indication of the high quality of the energy saving projects approved for funding.

4.4.2.5.3 2011 PSECA Initiative Performance Forecast

In 2011 the Companies expect to provide additional EEC incentive dollars to successful participants in a second round of PSECA funding. This second tranche consists of projects designed to reduce natural gas consumption and greenhouse gas emissions of K through 12 schools.

Table 4-14: PSECA Initiative Program Forecast

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
New Const	FEI	-	-		-		-	
	FEVI	-	-		-		-	
Retrofit	FEI	12	800	24	30,830	322,840	0%	0.7
	FEVI	2	208	9	5,497	58,745	0%	1.0
TOTALS		14	1,008	33	36,327	381,585	0%	0.7

Among this second group of projects are 12 central thermal plant upgrade projects, 4 of which consist of conversions to open loop type geoexchange heat pump systems with gas boiler backup. These will significantly reduce natural gas consumption and greenhouse gas emissions at each of the affected facilities.

Throughout 2011 and into 2012 FortisBC staff will expend a considerable amount of time and effort to inspect completed PSECA projects to ensure the approved energy saving measures have been built as described and are fully complete and operational prior to issuing payment. This will ensure incentives are only paid out where warranted.

Further to this, in 2013, after all the approved energy saving measures have been installed for a minimum of one full heating season, FortisBC staff will review the program's actual energy savings versus the claims of the energy studies. The results of the review will be used to refine the custom design program.

4.4.2.5.4 PSECA Initiative Summary

The combined 2010 and 2011 PSECA program activity will generate an overall TRC result above 1.4 by the time work in the program is finalized in late 2011 or early 2012. The Companies believe the PSECA initiative, offered in collaboration with the Climate Action Secretariat and BC Hydro, will successfully encourage public sector organizations to significantly reduce natural gas consumption and GHG emissions.

4.4.2.6 Fireplace Timers Pilot Program

4.4.2.6.1 Program Overview

Fireplace Timers Pilot Program	
Market	Retrofit
Duration	FEI: Nov 1, 2009 – Dec 31, 2011 FEVI: N/A
Incentive	Provision of fireplace timer at no charge, plus $30 per timer towards the cost of installation.

awareness and encourage greater uptake of the Efficient Commercial Water Heater program and subsequent program offerings within this sector.

4.4.3.2 Commercial Custom Design Program

4.4.3.2.1 Program Overview

Commercial Custom Design Program	
Market	New Construction / Retrofit
Duration	FEI: To be determined FEVI: To be determined
Incentive	• All energy conserving measures must exceed a TRC score of 1.0 to be eligible for an incentive • Incentives calculated as $5/GJ saved on the net present value of the natural gas savings over 50% of the estimated measure life to a maximum of 10 years • Incentives not to exceed 100% of the measure's incremental cost
Partner	BC Hydro
Overview	
Background	The Companies have historically offered incentives to commercial customers via prescriptive programs only. The prescriptive method assigns energy savings and incentive amounts to specified energy savings measures based on a generalization of how the measure will perform when installed. Many commercial customers have potential energy saving projects that are bigger and more complex than can be addressed in a prescriptive program due to the complexity and custom designed nature of their mechanical systems. A program to allow the Companies to encourage the implementation of these projects is necessary to capitalize on the natural gas saving opportunity they represent. The Commercial Custom Design program will meet this need by providing incentives tailored to suit the energy saving measures specific to each individual participant's project.
Description	The program seeks to capture energy savings associated with measures (i.e. technologies, systems, or operational strategies) that are otherwise difficult to incent as part of a prescriptive program because they are complex, and may include multiple measures with interactive effects in one project. This custom program will capitalize upon the creative potential of the marketplace, and help foster expertise in advanced energy efficiency design in BC. It is expected that most participants will be from sectors such as: 1. Large commercial facilities; 2. Large multifamily residential buildings; 3. Institutional and government; 4. Agriculture; and 5. Manufacturing (where measures address space or water heating). For such groups, the potential to achieve gas consumption savings by incorporating measures specifically engineered to suit their particular situation and needs is

<table>
<tr><td></td><td>expected to significantly surpass what can be accomplished via a prescriptive program. These may include measures that will:
• Make use of alternative energies, with gas backup
• improve building envelope performance;
• use more efficient gas burning equipment or systems;
• recover and reuse energy that is currently lost;
• capture and use solar energy for heating air or water;
• reduce the rate of energy consumption by systems or equipment in low occupancy periods; and
• eliminate unnecessary energy usage by shutting off idling or unneeded equipment
Energy saving measures will be presented to the Companies for review, in an energy study format prepared by a qualified consultant. Qualified consultants are engineering professionals, retained by the program participants, who meet the technical proficiency and experience requirements of the Companies.</td></tr>
<tr><td>Goals</td><td>• To capture energy savings from otherwise difficult to incent measures including whole building measures.
• To foster additional capacity and design expertise with custom energy savings measures in BC.
• Maintain a program TRC score greater than 1.0 and optimize the proportion of incentives over administration and marketing costs.</td></tr>
<tr><td colspan="2">Implementation</td></tr>
<tr><td>Administration</td><td>Handled by in-house EEC staff, BC Hydro Power Smart staff, and outside service providers where necessary.</td></tr>
<tr><td>Communications</td><td>Promotion of the custom program will be driven primarily via direct contact with target participants by the Companies’ staff or the program’s qualified consultants. Target customers should include:
o Health care administrators;
o Education administrators;
o Large institutional property managers (i.e. Nexacor, Profac, and so on);
o Municipalities – facilities and/or energy managers as well as municipal planners;
o Provincial government - facilities and/or energy managers; and
o Builders and developers.
Additional promotion via:
▪ Speaking engagements, where ever possible, to the target audience;
▪ Lunch and learn sessions with relevant professionals such as: energy managers, architects, engineering consultants, property developers.
Potential magazine and webpage advertisements with publications and organizations such as: AIBC / ArchitectureBC magazine, APEGBC / Innovation magazine, BOMA BC eNews, ASHRAE-BC Totem newsletter, Agriculture Climate Action Initiative funding catalogue, and BC Greenhouse Growers Association.</td></tr>
</table>

Evaluation Strategy	Simple deemed savings cannot be used due to the custom nature of the measures. The savings must be individually established for each and every participant. For new construction: the actual gas consumption will be compared to: a. Consumption prescribed per ASHRAE 90.1; and b. Qualified consultant's estimated consumption. For retrofits: Post retrofit, the actual gas consumption will be compared to: a. Weather normalized pre-retrofit gas consumption; and b. Qualified consultant's estimated consumption. Evaluation of the program savings and performance is assured by comparing pre construction data to post construction data. A thorough review could occur after approximately 30 participants have had their energy saving measures in place for at least one full year.

4.4.3.2.2 2010 Commercial Custom Design Program Results

The Companies have worked throughout 2010 on the development of the Commercial Custom Design program, in preparation for a phased roll out of the program in 2011. The Companies have completed the following items:

- Business case development and approval;
- Development of qualified consultant eligibility criteria and application;
- Development of joint Energy Study Guide for retrofit projects with program partner BC Hydro; and
- Development of Capital Cost Agreement, including approval letter, application form, and program general terms and conditions.
- Collaboration with School District No 23 (Central Okanagan) on a pilot study of a geo exchange heating system in a school setting.

The Companies have also worked with BC Hydro to develop the framework of a program specific partnership agreement that will allow the two utilities to operate the Commercial Custom Design program in tandem with BC Hydro's High Performance New Construction program and Power Smart Partners Retrofit program.

Significantly, the Companies have been using the proposed program's process flow and funding model within the PSECA initiative discussed above. As such the Companies have gained a great deal of experience working collaboratively with BC Hydro, as well as insight into the results that may be expected from the application of the funding model. Given that all energy saving measures must exceed the TRC hurdle to be eligible for funding, the Companies also expect a strong cost benefit ratio from the program, indicating cost effective energy saving measures are being incented.

4.4.3.2.3 2011 Commercial Custom Design Program Performance Forecast

Rolling out the Commercial Custom Design program will be a primary focus of the commercial programs team in 2011. Several items remain to be completed before the program can officially begin providing incentives. These include:

- Contribution agreement with BC Hydro to be finalized and signed;
- Program operations / process flow to be worked out with BC Hydro; and
- Energy Study agreement for natural gas only retrofit projects to be developed.

The Companies foresee adopting a phased roll out of the program. The new construction version of the program will be launched first and will begin providing incentives in collaboration with BC Hydro's High Performance New Construction program. Natural gas only projects for the retrofit market will be the next market segment served. Finally, retrofit projects touching on both electricity and natural gas will be provided with incentives. This will allow the utilities the opportunity to roll out the new construction program early in the new year while working through how to collaborate on retrofit projects. Meanwhile the Companies will be able to encourage retrofit projects that focus on natural gas reductions only. It should be noted that the Companies also intent to pursue a similar arrangement with FortisBC Inc. The program is complex, however, requiring a great deal of collaboration, well organized and detailed program processes, and ultimately dedicated administrative resources in order to ensure smooth operation. For this reason, the Companies are focusing on building the program with one partner at a time, beginning with BC Hydro.

4.4.3.2.4 Commercial Custom Design Program Summary

The Companies believe that, similar to the PSECA initiative, the new Commercial Custom Design program will encourage participants to implement energy saving measures that would not otherwise be installed without the incentive. The program will fill a role that is currently void within the Companies' commercial program offerings: providing incentives for non-prescriptive, custom designed and built measures to reduce natural gas consumption at the participant's facility. The program will leverage the reach of BC Hydro PowerSmart's current programs, to encourage the participation of more projects that the Companies could achieve by themselves. The Companies believe the proposed program will be a strong generator of value and successfully contribute to reduced natural gas consumption.

4.4.3.3 Continuous Optimization Program

4.4.3.3.1 Program Overview

Continuous Optimization Program	
Market	Retrofit
Duration	FEI: To be determined

Appendix K-1

EEC

1 INTRODUCTION

On April 16, 2009, the Commission released its Decision and Order No. G-36-09, which approved Energy Efficiency and Conservation ("EEC") funding for the 2009-2010 time period. The approved funding was $41.5 million in aggregate ($34.4 million for FEI and $7.1 million for FEVI for the period 2009 - 2010). FEI and FEVI applied in their respective 2010-2011 RRAs for additional funding for 2010 for interruptible industrial customers and for innovative technologies, and for funding for the overall EEC portfolio for 2011. The Commission approved FEI's and FEVI's NSAs (Order No. G-141-09 for FEI and Order No. G-140-09 for FEVI, both dated November 26, 2009), including the approval of EEC funding for 2010 and 2011.

As contemplated in the FEI and FEVI 2008 EEC application and addressed in Commission Order No. G-36-09, the Companies have established an EEC Stakeholder Group to seek input on the refinement of existing and development of new EEC programs and provide information to stakeholders about progress and development of its overall EEC initiatives. The Stakeholder Group meetings are an important forum for the Companies to get general feedback in all areas of the overall EEC initiative.

Subsequent to the approval of FEI's and FEVI's expanded EEC initiatives, the Province of BC has reaffirmed and strengthened its commitment to energy efficiency and conservation through the enactment of the *Clean Energy Act* ("CEA"). Energy efficiency and conservation, greenhouse gas emission reductions and the promotion of innovative clean energy development in BC are core themes in the CEA. The Companies' EEC proposals and funding requests are aligned with British Columbia's energy objectives as set out in the CEA.

This Appendix outlines the Companies' EEC funding requests for 2012 and 2013, and outlines in Section 5 below some additional changes that the Companies are proposing to:

a) expand customer eligibility for participation in EEC programs to include Interruptible Industrial customers of FEVI and to offer EEC programs to customers of FEW; and

b) modify the benefit-cost analysis by which EEC projects are assessed. The Companies believe that the requested funding for 2012 and 2013 is reasonable as it is well supported by the achievable potential identified in the Companies' recently completed Conservation Potential Review (discussed further below). The Conservation Potential Review summary is attached in Appendix K-2.

In the Companies' Long Term Resource Plan filed in 2010 ("2010 LTRP"), and in the regulatory proceeding related to the 2010 LTRP, the Companies had indicated that they believed that longer-term, sustained EEC funding was the optimum approach, and in response to one Information Request from the Commercial Energy Customers, had indicated that an EEC funding approval period of five years would be appropriate. Given that current EEC funding approvals expire at the end of 2011, and that this Revenue Requirement Application period is two years covering 2012 and 2013, the Companies have made a decision to proceed with requesting EEC funding approval to cover the years 2012 and 2013. The Companies will incorporate a longer-term funding request, and will incorporate the EEC scenario planning and impacts on demand forecasting, in the next Long Term Resource Plan, which FEU anticipates filing in 2013.

The remainder of this section is divided into the following parts:

- A discussion of the total requested funding for 2012 and 2013 (Section 2);
- A discussion of the budgeted EEC funding within the total funding envelope for previously approved "conventional" and Innovative Technologies program areas (Section 3);
- A discussion of the budgeted EEC funding within the total funding envelope for New Initiatives (Section 4); and
- A request for additional approvals related to customers of FEW, Interruptible Industrial customers on FEVI and benefit-cost analysis used to screen the Companies' EEC activity moving forward (Section 5); and
- Conclusion (Section 6).

2 REQUESTED FUNDING ENVELOPE FOR 2012 AND 2013

FEI and FEVI have had access to sufficient funding for 2010 activities, and the existing approvals ensure that there is sufficient funding for continued EEC activities in 2011. The approved funding for 2010 and 2011 is summarized in Table K-1 below.

Table K-1: Approved EEC Funding for 2010 and 2011

($ thousands)	**FEI**		**FEVI**	
	2010	**2011**	**2010**	**2011**
Residential, Commercial, Joint Initiatives, and CEO Programs	20,675	20,675	4,126	4,126
Affordable Housing	2,400	2,400	600	600
Industrial Interruptible	435	1,875	-	-
Innovative Technologies	2,300	4,669	478	956
Total	**25,845**	**29,619**	**5,204**	**5,682**

A summary of the Companies' overall request for approval for each EEC program area for 2012 and 2013 can be found in Table K-2 below:

Table K-2: 2012 and 2013 Overall EEC Funding Request by Program Area

	2012 Proposed Funding ($000's)	2013 Proposed Funding ($000's)
	Total	**Total**
Previously Approved EEC Activity		
Conventional EEC Activity		
Residential	9,500	9,500
High Carbon Fuel Switching	2,000	2,000
Low Income	5,000	5,000
Commercial	14,500	14,500
Conservation Education and Outreach	5,000	5,000
Industrial	2,000	2,000
Subtotal - Conventional EEC Activity	***38,000***	***38,000***
Subtotal - Innovative Technologies inc. NGV	***11,500***	***11,500***
Subtotal - Previously Approved EEC Activity	***49,500***	***49,500***
New Initiatives		
Furnace Scrap-It program	**10,000**	**10,000**
Solar Thermal	**4,000**	**4,000**
TES for Schools	**11,000**	**11,000**
Subtotal - New Initiatives	***25,000***	***25,000***
Total Funding	**74,500**	**74,500**

The Companies' proposed increase in the total EEC funding envelope for 2012 and 2013 is based on:

- increases in areas of program activity in respect of which the Commission has already approved funding in Orders G-36-09, G-140-09 and G-141-09, discussed in Section 3 below, and
- budgets for, and activity relating to some new initiatives, discussed in Section 4.

While the funding requests represent an increase in EEC spending, the Companies have proposed a revised financial treatment for EEC spending in 2012 and 2013 (see Section 6.3.2 of the Application) that protects ratepayers in the event that the Companies are unable to spend the full amount within the funding envelope ($74.5 million/year). Under the proposed financial treatment, however, only $20 million per year of EEC spending is reflected in the 2012-2013 rate base and revenue requirements. $20 million was selected as the appropriate number since it aligns with the expenditures of approximately $17.7 million that the Companies were able to commit to EEC activity in 2010.

Actual EEC spending in 2012 and 2013 above $20 million per year will be recorded in non-rate base deferral account (attracting AFUDC) and will not commence recovery in rates until 2014. This revised financial approach is intended to ensure that customers only pay for actual EEC expenditures that are incurred during 2012 and 2013. Stakeholders will have the opportunity to comment on proposed budgets for upcoming years during the EEC Stakeholder Group meeting held in the fall of each year, once programs have been planned for the following year. Further, the Companies file the EEC Annual Report by March 31 each year, giving the Commission and stakeholders an additional opportunity to comment on proposed EEC activity, including planned budgets, for the upcoming year. For further details on how the EEC expenditures are treated for 2012 and 2013, please refer to Section 6.3.2.1 in the Application.

Consistent with the Commission's Decision in the EEC proceeding, the Companies propose that

- the overall funding level of $74.5 million be considered a level that would not be exceeded;
- the Companies will spend those funds only on approved Program Areas; and
- the Companies will retain their ability to re-allocate funds initially budgeted for one approved Program Area to another approved Program Area(s) and the FEU will report on funding transfers in their Annual Report.

The Companies believe that retaining the flexibility to allocate more of the approved funding to successful previously approved Program Areas and scale back other programs that are not performing as well as expected (subject to the requirements and constraints of the DSM Regulation) will continue to provide a strong results-based framework for the Companies' EEC initiatives. It will support the overall success and cost effectiveness of the EEC program portfolio as a whole. This approach and support from customer groups is outlined in the following passage from the EEC Decision on pages 41-42:

> *"Terasen summarizes its proposal for accountability mechanisms as follows:*
>
> *In this Application the Companies have recognized the need for accountability for the funds approved for EEC programs. First, any funds not spent will not be charged to the regulatory asset deferral account. Second, the Companies intend to monitor the portfolio TRC on a monthly basis, and have proposed to file an Annual EEC Report with the Commission by the end of the first quarter every year. The Report will detail program activity, expenditures, and cost-benefit results for the previous year, as well as describe program activity and provide forecasts for the upcoming year. Third, in the event that the relief sought is granted, the Companies would form and engage an EEC stakeholder group with membership representing a broad cross section of stakeholders identified in the Application. Fourth, the Companies have indicated their intention to hold annual EEC workshops with stakeholders, at which the Companies would present updates on*

program progress and obtain stakeholder Input on new programs and refinements to existing programs. Fifth, the Companies are proposing to develop many of the programs for the commercial sector and the DSM for Affordable Housing sector in conjunction with stakeholder advisory groups." (Terasen Argument, p. 39)

Intervenor Positions
BCSEA-BCSC states that they: ". . . support this [funding] approach, noting that the proposed accountability mechanisms are designed to be more effective and efficient than having on-going Commission involvement in decision-making within the portfolio during the Funding Period" and BCSEA-SCBC acknowledge and support the additional accountability mechanisms proposed by Terasen in [Terasen Argument] paragraph 112." (BCSEA-SCBC Argument, pp. 5, 20)

BCOAPO argues that, should the Application be approved, an independent audit process should be Required with respect particularly to free ridership, attribution and redirection of funds. (BCOAPO Argument, p. 14)

Commission Determination
The Commission Panel accepts Terasen's accountability undertakings, and considers that, while the proposal to evaluate the EEC project using the TRC test at the Portfolio level has been accepted,TRC calculations for each program area, initiative and measure should also be included in the accountability reporting as a means of assessing the components of the Project and their ongoing effectiveness.

Commission Panel directs that the annual EEC Report include the following:

- *TRC, RIM, UC, and Participant test calculations of DSM at the Program Area initiative and individual measure levels in addition to the total Portfolio level reporting. Reporting of the Residential & Commercial EE program areas should also be made at the New Construction and Retrofit levels.*
- *any inter and intra Program Area initiative funding transfers, with supporting rationale, and the impact of such transfers on the transferor and transferee Program areas, initiatives, and measures as the case may be.*
- *data for fuel switching programs should be tracked in a manner which allows for reporting types of fuels replaced by natural gas, including estimated GHG impacts."*

The incremental funding amounts in previously approved Program Areas compared to 2010/11 funding levels are discussed in Section 3 below. Within the previously approved Program Areas, the amounts budgeted for "conventional" activity are based on increases to budgets for the "conventional" EEC activity reported in the 2009 and 2010 Annual Reports (included as Appendix K-3 and K-4 respectively). 2009 and 2010 "conventional" EEC activity in turn was based upon the "bottom up" budgets that were developed for the 2008 EEC Application. The budgeted total amounts for "conventional" or non-Innovative Technology activity for 2010 and 2011 for FEI and FEVI were approximately $28.2 million and $29.7 million respectively. The Companies have budgeted for an increase for "conventional" EEC activity to $38 million/year for each of 2012 and 2013, which will allow the Companies to continue and expand the "conventional" EEC activities derived from the "bottom up" budgets developed for the original EEC Application. Further, the Companies have increased the Innovative Technology Program area request in 2012 and 2013 to $11.5 million. Budgeted EEC funding for previously approved EEC activity is the subject matter of the next section below.

3 FUNDING FOR PREVIOUSLY APPROVED EEC ACTIVITY

In Orders G-36-09, G-140-09 and G-141-09, the Commission has approved funding and activity for the following types of EEC programming: residential, commercial, industrial, joint initiatives, low income, conservation education and outreach and Innovative Technologies. The material below in Sections 3.1 and 3.2 describes increases to funding for this previously approved activity. For the purposes of organizing this write-up, activity for Natural Gas Vehicles has been included with Innovative Technologies under the heading of "Previously Approved EEC Activity" EEC programs. Although the Companies believe that is an accurate characterization, we wish to make clear that we recognize that this issue is being addressed in a separate regulatory process regarding the approval to expend EEC funds for activity relating to NGV, and that this issue remains outstanding at the time of filing.

3.1 EEC Funding for "Conventional" EEC Activity

For the purposes of this discussion, "conventional" EEC activity refers to all activity excluding Innovative Technologies and New Initiatives, and supports EEC activity related to residential (including low income), commercial and industrial customers. The Companies propose that the general areas of activity and programs for "conventional" EEC activity that were implemented in 2010 and 2011 be extended to cover the 2012 and 2013 time period, with budgeted increases to funding for most program areas. Descriptions of that activity and these programs for 2011 can be found in the Companies' 2010 Annual EEC Report, submitted to the Commission on March 31 2011, in sections 3, 4, 5, 6, 7, 8, 9 and 11. This 2010 EEC Annual Report is also included as Appendix K-4 to this Application. Table K-2 above outlines the Companies' budgeted funding levels for "conventional" EEC activity. The Companies have not yet commenced detailed program design for 2012 and 2013, and the subsequent development of individual program budgets for "conventional" EEC activity, but it could be expected to be very similar to the type of "conventional" activity outlined in the Companies' 2010 EEC Annual Report, with budgeted increases to funding levels to allow for the expansion of "conventional" EEC activity. It is the Companies' intention to develop program activity for 2012 over the course of 2011, and as in previous years, contemplated program activity for 2012 will be presented to the EEC Stakeholder group in the EEC Stakeholder meeting to be held in Fall 2011, and feedback from this group will be solicited and incorporated prior to any refinement to existing program or new programs launching in 2012.

The Companies' proposed budget for EEC programs in 2012 and 2013 reflects the following changes from the budgets established for previously approved "conventional" EEC activity in 2011:

- Consolidation of "Joint Initiatives" activity with "Residential" as all the activity funded in the Joint Initiatives program area undertaken to date has been for residential customers. Collaborative activity with other utilities and government is taking place in all other program areas; it is not, however, broken out into a separate funding category in these other program areas. It makes sense to align funding for collaborative activity for residential customers within the residential program area.
- An increase in budgeted funding for residential customers from approximately $5.2 million (for Residential and Joint Initiatives activity combined) to $9.5 million. The Companies anticipate that a Residential New Home Construction Program, a Domestic Hot Water Program and participation in such collaborative programs as LiveSmartBC will require a larger budget for EEC activity for residential customers than previously established. Residential customers form the bulk of the Companies' accounts, and programs aimed at these customers are very important in creating the "culture of conservation" that will be needed in order to achieve government's energy objectives.
- An increase in budgeted funding for high-carbon fuel switching to lower carbon fuels (e.g. Heating oil to natural gas) from approximately $1.5 million to $2 million. This activity would be aimed at residential and commercial customers, and would have the goal of moving these customers off propane and heating oil, and onto natural gas. It could also be aimed at moving customers onto alternative forms of energy, such as geoexchange with natural gas backup. This funding does not include fuel switching from electricity to natural gas.
- An increase in budgeted funding for low income customers from $3 million to $5 million. Activity in this particular area has good support from government and stakeholders.
- An increase in budgeted funding for conservation education and outreach from $3.5 million to $5 million as the Companies seek to expand activity around influencing conservation behaviours by British Columbians.
- An increase in budgeted funding for all industrial customers, regardless of whether they are on a firm or an interruptible rate, from $1.875 million to $2 million. This is a relatively new area of activity for the Companies, and it is anticipated that we will need time to gain knowledge and experience in this area, therefore only this modest increase is anticipated over the 2012 and 2013 period.

The above budgets for "conventional" EEC activity program areas form the basis for the overall funding request, but as indicated above the Companies are proposing to maintain the approach used since the 2009 EEC Decision whereby the Companies retain the flexibility to reallocate funding among any of the approved program areas as required to optimize the portfolio.

The Companies' recently completed Conservation Potential Review, the Summary for which is attached as Appendix K-2, found that the Most Likely Achievable Potential energy savings in the Residential, Commercial and Industrial areas of activity were 2.2 million GJ/year by 2015, and 10.3 million GJ/year by 2030. This represents significant opportunity for energy savings. In 2010, the Companies committed approximately $12.1 million in EEC funding to non-NGV EEC activity aimed at the Companies' Residential, Commercial and Industrial customers, for annual energy savings of 166,110 GJ/year. While the Companies are relatively new to this scale of EEC expenditure and activity, and the funds committed in 2010 included some "one-time" costs such as a DSM tracking system, it can be seen that in order to achieve the energy savings found to be available in the CPR, higher expenditures will be necessary. Hence, the Companies believe that the proposed increase in the EEC funding envelope for 2012 and 2013, reflecting budgeted increases in "conventional" EEC programs, is warranted.

3.2 Innovative Technologies, including Natural Gas Vehicles ("NGV")

In the 2008 EEC application, FEI and FEVI requested funding for Innovative Technologies since the utility is in a unique position to foster and further the deployment of forward looking low carbon technologies. On April 16, 2009, the Commission issued the EEC Decision approving funding for FEI and FEVI for 2009 and 2010 programs. While the Companies did not receive approval for expenditures for the Innovative Technologies Program Area as part of that application, the Commission directed the Companies to bring forward projects for consideration as they became more fully developed[1].

FEI and FEVI submitted their respective applications for 2010 – 2011 Revenue Requirements and Delivery Rates on June 15, 2009 and June 29, 2009, respectively, which proposed innovative technologies programs and expenditures in order to meet the Commission's directives in Order No. G-36-09. On November 26, 2009, the Commission issued Order No. G-141-09 and Order No. G-140-09 approving the Innovative Technologies programs and expenditures as listed in the Negotiated Settlement Agreement ("NSA") for both FEI and FEVI.

As part of their respective NSAs, the parties agreed that the Innovative Technologies Program Area will be managed by FEI and FEVI as a separate segment of the overall EEC portfolio and have a weighted total resource cost ("TRC") of 1.0 or more. A program manager was hired in the second quarter of 2010 to develop program design and framework for the non-NGV activity in the Innovative Technologies program area.

[1] BCUC Decision in the matter of Fortis BC Energy Inc. and Fortis BC Energy (Vancouver Island) Inc. Energy Efficiency and Conservation Application, April 16, 2009, p. 26.

On January 14, 2011, FEI received Decision Order G-6-11 which granted interim approval of CNG Service for Waste Management to fuel their fleet of 20 garbage trucks. In this decision, the Commission raised a potential issue with respect to the use of EEC incentives for NGV vehicle reimbursement.[2] As discussed in the 2010 EEC Annual Report ("Report"), filed March 31, 2011, the Companies believe that the use of Innovative Technologies Program Area EEC funding for NGV initiatives is consistent with previous Commission decisions[3] (Order Nos. G-36-09, G-141-09, and G-140-09), and that FEI has been open and transparent with stakeholders about EEC activities and expenditures, including the use of EEC incentives for NGV.[4] In the Report, the Companies requested that the Commission provide confirmation of the Companies' compliance with past orders without additional process, or alternatively, if the Commission was unable to provide this confirmation, the Commission provide its concurrence for the Companies to proceed with EEC incentive funding.

The Commission subsequently issued Order No. G-70-11 on April 20, 2011 which initiated an expedited process to review the appropriateness of the Companies' use of EEC funds as NGV incentives. The initial regulatory timetable is scheduled to conclude near the end of May 2011. Therefore the Utilities have developed their EEC funding request (and NGV volume and revenue forecast) in this RRA assuming that EEC incentive funding for NGV initiatives have been approved by the Commission.

In this RRA, the Companies have budgeted $11.5 million in 2012 and $11.5 million in 2013 to fund technologies with low market penetration including NGV, and enabling activities such as metering for these technologies, within the Innovative Technologies program area. Recognizing that the Commission's review process of incentive funding for NGV initiatives has not reached a conclusion at this time, the Companies have divided the Innovative Technologies section into two parts. The first section describes the $3 million funding contemplated ($1.5 million per year for each of 2012 and 2013) associated with non-NGV initiatives fostering the deployment of low carbon technologies. The second section describes the Companies' NGV funding contemplated of $20 million over two years ($10 million per year for each of 2012 and 2013). In each separate section the Companies provide some background on the programs, a description of the programs and its objectives, followed by a rationale of the funding amount contemplated by the Companies.

3.2.1 INNOVATIVE TECHNOLOGIES - NON-NGV INITIATIVES

Innovative technologies are solutions that the Companies can support through programs delivering energy reductions and savings to their customers for now and into the future. All programs within this program area are to foster and further the deployment of low carbon technologies. Those low carbon technologies are best described as being market ready but have little or no market penetration in BC. They can also be defined as emerging and/or

[2] Commission Order No. G-6-11, at page 5
[3] 2010 EEC Annual Report, at page 203
[4] 2010 EEC Annual Report, at page 216

enabling technologies. Some of these technologies include, but are not limited to, solar thermal domestic hot water systems, solar air systems, ground source heat pumps (“GSHPs”), hydronic systems, sterling engines, micro co-generation, and fuel cells. Hydronic systems can be classified as enabling technologies as they have the flexibility and potential to receive future energy from District Energy Systems (“DES”).

The Innovative Technology programs pursue a number of objectives in order to support, review, and validate market-ready technologies. More specifically they focus on:

- Supporting local, provincial, and federal governments with climate action goals and policies focused on fostering the development of market-ready technologies that promote energy conservation and efficiency and the use of clean or renewable resources; and
- Evaluating market-ready technologies and conducting pilot studies and/or demonstration projects to validate manufacturer's claims about equipment and system performance, and energy efficiency.

The Companies are budgeting $3 million of the total requested funding envelope over 2 years ($1.5 million for each of 2012 and 2013) to support those objectives.

In 2010, the Companies committed $372,000 in funds to non-NGV Innovative Technologies activity, and we are estimating a commitment of approximately $715,000 in 2011. The 2011 commitments are almost double the amounts in 2010 due to the increased momentum of establishing and developing industry contacts, technology awareness and expertise, and further program design. The Companies expect this trend to continue into 2012 and 2013 as further market momentum for these technologies is gained.

The Innovative Technologies program area plays an integral role in the Companies' overall commitment to EEC activities, not only in reducing or replacing natural gas consumption with lower carbon technologies, but also in supporting the government’s climate action goals. The Companies believe also that there is a strong need for measurement and verification of energy savings for these lower carbon technologies through conducting pilots and/or demonstration projects. The data from pilots can be used to validate manufacturer’s claims about energy savings, help improve the quality and installation of future systems, and be used to understand and reduce market barriers. Traditionally costs to produce, distribute, install and monitor these technologies are higher due to a lack of market “scale” and require incentives for market transformation.

The Companies believe that continued funding for Innovative Technologies is critical in validating and piloting the energy saving performance of low carbon technologies for the development of future energy efficiency and conservation programs within the residential, commercial and industrial sectors.

3.2.2 INNOVATIVE TECHNOLOGIES - NATURAL GAS VEHICLE ("NGV") INITIATIVES

NGVs, which use liquefied natural gas ("LNG") or compressed natural gas ("CNG") as a heavy duty vehicle fuel (trucks and marine vessels), are considered part of the Innovative Technologies Program Area for two reasons. First, technologies used in NGV applications are market-ready, but can be classified as emerging technologies in the BC context as they have minimal market penetration in BC. Second, the Commercial NGV Demonstration program achieves GHG emissions reductions by displacing high-carbon diesel fuel with low-carbon natural gas. Through this program, the Companies (FEI and FEVI) provide funding to offset, in whole or in part, the incremental vehicle cost difference between an NGV compared to its diesel equivalent. The Companies' EEC request includes $10 million in 2012 and $10 million in 2013 to fund its NGV initiatives within the Innovative Technologies Program Area. Based on information provided by equipment vendors, the capital cost premiums associated with CNG and LNG vehicles are approximately:

- CNG Vocational truck (refuse, waste hauler) - $27,000 - $45,000
- CNG Transit bus - $50,000 - $70,000
- LNG Class 8 tractor - $80,000 - $90,000
- LNG Marine vessel - $3 - $4 million

In 2012 and 2013 the Companies anticipate a funding level which ranges from 80 percent to 100 percent of the incremental cost differential.[5] An exact percentage has not yet been determined and its timing will likely depend upon level of adoption of each vehicle category and the capital cost premium. The Utilities believe that capital cost premiums will decrease as NGV adoption increases in BC. Future adjustments to the funding levels will be assessed as NGV adoption occurs.

The Utilities have used these assumptions to calculate the approximate number of vehicles which could be funded with $10 million in 2012 and $10 million in 2013.[6] The potential number of vehicles which could be incented with this amount is presented in the volume forecast in Appendix I of this Application. FEI anticipates market adoption in vocational trucks, Class 8 tractors and buses to occur 2012 and 2013, with one marine vessel forecast for 2013. FEI also notes that a lag may exist between when vehicles are purchased, delivered and ready for

[5] Funding levels during 2010 and 2011 have ranged from 80 percent – 100 percent of the incremental cost between NGVs and its diesel equivalent. Future funding may be lower than 80 percent depending upon the level of NGV adoption and capital cost premium.

[6] At this time, FEI offers incentive funding ranging between 80 – 100 percent of the incremental cost. This reimbursement level may decrease in the future as NGV adoption increases and cost premiums decrease, however the exact amount and date is unknown at this time.

fuelling service. This means load additions do not necessarily occur in the same year as incentive payments are issued.

The growth of the NGV refueling business is inherently reliant upon the adoption of NGVs in our service territory and the Utilities believe that the adoption of NGVs in our service territory depends upon the continued availability of these EEC incentives for NGV adoption. The Utilities wish to make clear that there is no conditional connection between EEC incentives for NGV and the need for the Utilities to also build and operate the NGV refueling stations, other than that the availability of both as options are required in order to see the NGV adoption required to provide meaningful and material benefit to our existing customers. Further, regardless of who provides the fueling service the benefits of increased throughput across the FEI system for CNG and LNG will benefit existing customers.

For additional information on the NGV forecast and potential benefits of our NGV initiatives, please refer to Appendix I of this Application.

4 NEW INITIATIVES

The Companies' proposed EEC funding envelope for 2012 and 2013 includes funding for several new programs that have not yet been considered by the Commission and do not meet the cost effectiveness test requirements currently applicable to the Companies' EEC programs. Changes to the cost effectiveness tests such as employing the Societal Cost Test ("SCT") rather than the TRC or amendments to the DSM Regulation will be required in order for these new initiatives to meet cost effectiveness thresholds or other stipulations of the DSM regulation. The SCT is discussed in Section 5.2.2 below. In other words, the Companies cannot pursue these initiatives in the absence of a change to employing the Societal Cost Test or to the DSM Regulation. The reason that funding for new initiatives has been included in the overall requested funding envelope is that FortisBC has been made aware that the Ministry of Energy and Mines is considering developing amendments to the DSM Regulation and the program proposals below are intended to comply with possible amendments. The final form of DSM Regulation amendments, if any, and the timing of when they occur, is subject to the approval of the Minister of Energy and Mines. The Companies believe that it is most efficient and logical to include a request for funding in this application, rather than having to reapply for funding for New Initiatives if and when any changes to the DSM Regulation come into effect.

It is possible to address this funding now, as part of this RRA, because the proposed changes to the regulatory treatment of EEC funding in 2012 and 2013 will ensure that customers will not pay for the costs of these new initiatives in rates unless the programs proceed and the funds are actually spent. The Companies have also included a request (discussed in Section 5.2.2 below) to adopt the SCT for all EEC activity, including for these New Initiatives.

4.1 Furnace Scrap-It Program

The Companies requested EEC funding includes a budget of $10 million per year for each of 2012 and 2013 for a Furnace Scrap-It Program. Supporting energy bill reductions for families and small businesses throughout the FortisBC service territory, this proposed program would replace about 10,000 furnaces per year with super-efficient ones. Although many standard and mid-efficient furnaces are theoretically beyond their rated operating life (~20 years), they continue to function and owners are not upgrading them due to a poor payback period on the purchase of a new furnace (~20 years at current rates). However, the owners would have to replace the furnaces in 5-10 years anyway (and incur the full cost). As such, this program would provide an incentive for early replacement, resulting in short-term cost savings and emission reductions.

It is estimated that there are 560,000 standard- and mid-efficiency furnaces in British Columbia. In 2009, the total furnace shipments to BC were 36,000, although a sizable proportion of those are for new construction. Assuming two-thirds of those furnaces shipped were replacement, it would take 23 years for British Columbians to replace their inefficient furnaces, a lost opportunity for financial savings for homes and small businesses.

The LiveSmart BC: Efficiency Incentive Program is expected to provide rebates for about 3,900 super-efficient furnaces in 2011. The Furnace Scrap-It program would support an additional 10,000 furnaces per year, some of which might go through the LiveSmart program as well. This would accelerate the replacement of British Columbia's inefficient furnaces by about 50 percent.

There are several "non-energy benefits" of a furnace replacement that are not currently considered in the approved DSM evaluation models when evaluating programs. The Companies have outlined in Section 5.2.2 below a proposal to move to the SCT to evaluate all EEC activity. Such a change would allow the Companies to offer this program to our customers. As can be seen in the Residential section of the CPR Summary attached as Appendix K-2, space heating accounts for 80 percent of the residential energy savings, and the largest contributor to this space heating energy savings is a furnace early retirement initiative. The Companies' requested EEC funding includes a budget of $10 million per year for each of 2012 and 2013, to fund approximately 10,000 furnace retirements with an incentive of $1000 per participant. For the reasons described above, the Companies believe that the budgeted amount of funding is justified and should be reflected in the overall funding envelope ultimately approved by the Commission.

4.2 Solar Thermal

The Companies' requested funding includes a budget of $8 million over the next 2 years ($4 million for 2012 and $4 million for 2013) for Solar Thermal. This program offers energy source reductions from natural gas to solar for domestic hot water for residential and commercial applications, and solar for space conditioning preheat for commercial and industrial applications. Natural gas would still be part of the picture as a backup fuel source. It also supports the government's climate action goals and policies focused on fostering the development of market-ready technologies that promote energy conservation and efficiency and the use of renewable resources. Both of those initiatives will reduce natural gas consumption and carbon emissions.

There is a strong need for a utility program in this area, as Natural Resources Canada's EcoEnergy for Renewable Heat program and SolarBC's Residential program offering incentives for solar thermal were discontinued effective December 31, 2010. Budgets at other levels of government (provincial and municipal) are inadequate to provide the kind of scale needed to start the market transformation effort for solar thermal as customers are not willing to absorb the high upfront capital cost for the energy bill savings and other benefits expected. The SolarBC Residential program offered incentives to encourage 540 households across BC to install solar hot water which resulted in 4,353 GJ saved every year and annual GHG emission reductions of 94 tonnes of CO_2. 240 or (54 percent) of all the residential installations since 2008 occurred in 2010. NRCan's EcoEnergy for Renewable Heat program also proved to be a success, funding over $20.5 million for 1,268 commercial solar thermal hot water systems and industrial solar for space conditioning preheat systems throughout Canada. 514 or (41 percent) of all the commercial and industrial installations since 2007 occurred in 2010. The results of both the SolarBC Residential and NRCan's EcoEnergy for Renewable Heat program indicate an active industry interest for solar thermal and resulted in an increased uptake percentage each year that those programs were available. The Companies believe that those program results indicate a strong demand for solar thermal within the residential, commercial and industrial sectors to support the $8 million that the Companies have budgeted. The Companies also believe that it is essential for market transformation to continue the positive momentum that has been gained over the last few years through those programs with developing its market share, associated jobs and economic benefits.

Solar thermal projects fail the Total Resource Cost ("TRC") test, due to the high incremental cost of solar equipment, and the prevailing low cost of natural gas. Consequently, solar thermal programs will not be able to proceed in any material fashion in the absence of the application of the Societal Cost Test as requested by the Companies. In the case of solar thermal, using a deemed adder for non-energy benefits of 30 percent, as proposed in Section 5.2.2 below, would effectively capture such non-energy benefits as job creation, and environmental attributes.

For the reasons described above, the Companies believe that the budgeted amount of funding for Solar thermal is justified and should be reflected in the overall EEC funding envelope ultimately approved by the Commission.

4.3 Thermal Energy Services for Schools

FortisBC is proposing a $22 million incentive program for geoexchange and energy efficiency retrofits in up to 260 schools over two years. The TES for Schools program would provide capital incentives for state-of-the-art low carbon energy systems such as geoexchange systems, high-efficiency boiler upgrades, as well as educational energy monitoring equipment. These state-of-the-art low carbon energy systems continue to incorporate natural gas as a critical energy input, whether as the primary component or as a back-up and peaking energy source.

The need to replace worn out equipment (such as central boilers, individual rooftop air-handling units, and ancillary equipment) is urgent for many schools across BC, but the incremental costs are a major barrier for schools to proceed with replacing their energy systems. In addition, schools are challenged with compliance with government legislation to become carbon neutral via reduction in carbon emissions and/or through the purchase of carbon offsets. Faced with limited budgets and constraints on capital and debt, the ability of school districts to achieve these goals is limited.

To foster a competitive market, incentives would be available for projects using a third party ownership model and those owned and operated by school boards. Incentive levels are structured to ensure positive economics for participating school districts, while maximizing ratepayer value. As the highly efficient geoexchange systems do not meet the current cost-effectiveness test due to high incremental capital costs, the budgeted $22 million in program spending will employ a pooled approach in the cost-effectiveness evaluations for each school district, which aims to minimize GHG emissions while ensuring economical solutions through the selection of the optimal combination of technologies to fit within both operating and capital budget constraints. This approach enables a major increase in the total number of school retrofits and expands the share of geoexchange installations, while keeping incentives to 50 percent or below of a school district’s combined equipment capital costs.

The scope of this program has been restricted to schools to address a clearly defined financial need, to provide benefits that target BC families, and to provide important educational and training opportunities about energy efficiency and environmental stewardship for present and future generations of students, which benefits would be among those captured using the 30 percent proposed deemed adder for non-energy benefits in the Societal Cost Test, as outlined in Section 5.2.2 below.

5 ADDITIONAL APPROVALS REQUESTED

In addition to funding approvals, in the EEC Decision the Companies received a number of additional approvals related to the principles guiding EEC activity, how programs are to be evaluated, and oversight mechanisms. The Companies are proposing some changes to some of these guiding principles discussed in this section, but by and large the Companies are proposing no changes to the existing EEC framework.

5.1 Elements of Existing EEC Framework to be Retained

Most aspects of the existing EEC framework continue to make sense going forward. The key approvals previously granted to which the Companies are proposing no change are as follows:

- The Commission approves an overall funding envelope comprised of a portfolio of approved program areas. Consistent with that notion, the Companies will continue to have the ability to move funds between programs and program areas to optimize the portfolio;
- Continue to use the portfolio level approach to benefit-cost analysis such that the overall portfolio including all EEC-funded activity should have a benefit-cost result of 1.0 or greater. (The Companies are proposing a change to measure cost-effectiveness of the portfolio using the Societal Cost Test as discussed in Section 5.2.2 below);
- Continue to evaluate the Innovative Technologies portfolio of activity on a separate segment of the overall portfolio, with a weighted average benefit-cost test result of 1.0 or greater. (The Companies are proposing a change to measure cost-effectiveness of the Innovative Technologies portfolio using the Societal Cost Test, as the Companies are proposing in Section 5.2.2 below that the Societal Cost Test be used for all EEC activity, including Innovative Technologies);
- Continue to be able to offer programs and measures with a benefit-cost result of less than 1.0, but provide information in annual reporting as to why the program should continue, including information on any environmental or social or other goals supported by the program or measure;
- Continue to use the approved accountability mechanisms that the Companies have put in place, that is the EEC Stakeholder group, and EEC Annual Report, which offer the Commission and Stakeholders the opportunity to comment on proposed program activity. The EEC Annual Report includes a supporting rationale for funding transfers between approved program areas and funding transfer impacts. It also includes reporting on the benefit-cost analysis, and justification for continuing with programs and measures with a benefit-cost result of less than 1.0.
- Continue to be guided by the "EEC Program Principles" put forward originally in Section 5 of the EEC Application; and
- Continue to capitalize the approved EEC expenditure to a regulatory deferral account, and to amortize deferral account balances for a period of up to ten years. The regulatory treatment for the first $20 million per year of EEC spending in 2012 and 2013 is the same as the treatment for EEC spending in 2011 and before (as approved by BCUC Order No. G-36-09). The proposed regulatory treatment for 2012 and 2013 EEC spending in excess of $20 million per year, whereby these amounts are recorded in a non-rate base deferral account and recovery in rates is not commenced until 2014, constitutes a small departure from this treatment. The Companies have proposed this change to recognize the variability in customer participation that may occur in the forecast period and to mitigate the risk of recovery in rates for budgeted EEC spending that does not actually occur.

Further, the Companies' EEC activity will continue to comply with the requirements for adequacy as laid out in the DSM Regulation.

5.2 Proposed Changes to Existing EEC Framework

The Companies are proposing few changes to the existing approved EEC framework. The proposed changes, discussed in the remainder of this section, are:

- Expand all EEC programs eligibility to customers of FEW and to offer the Interruptible Industrial program to customers of FEVI; and
- Move to use of the Societal Cost Test as the primary means of evaluating the cost-effectiveness of the Companies' EEC activity.
- Include spillover in "Net-to-Gross estimates of program effects

The Companies believe that these changes will make EEC funding more widely available to customers, and will help to make the EEC program more effective.

5.2.1 ELIGIBILITY EXTENDED TO FEW AND INDUSTRIAL INTERRUPTIBLE CUSTOMERS OF FEVI

The Companies are proposing the following:

- To extend eligibility for EEC program participation to customers of FEW in order to comply with Order G-138-10.[7];
- To expand eligibility for participation in programs to Interruptible Industrial customers of FEVI; and
- In the Companies' 2010-2011 Revenue Requirements proceeding, the Companies did not apply for funding for EEC activity for Interruptible Industrial customers of FEVI, as the Companies had very little experience with Industrial DSM and wished to hire an Industrial Program Manager and start to develop an Industrial strategy based on FEI's larger industrial customer base. That Industrial Program Manager is now in place, and the Industrial strategy developed. Thus, the Companies feel it is now appropriate to expand eligibility for participation in EEC activity to Industrial customers of FEVI. The Industrial strategy can be found in Section 9.1.5 of the Companies' 2010 EEC Annual Report, which is included in Appendix K-4.

7 As per Commission's Reasons for Decision, Order No. G -138-10, as part of FEW (formally referred to as TGW) 2010-2011 RRA, indicating concerns about the lack of DSM initiatives in TGW's Application, and directing TGW to develop plans for DSM programs, consistent with British Columbia's energy objectives, in the next revenue requirements application.

5.2.2 ADOPTION OF THE SOCIETAL COST TEST AS THE PRIMARY COST-EFFECTIVENESS SCREEN

The Companies are proposing that the Societal Cost Test be used as the primary cost-effectiveness screen for all of the Companies' EEC activity, including "conventional" and Innovative Technologies, incorporating the following three proposed changes:

- The use of a social discount rate of 3 percent, rather than the Companies' weighted average cost of capital;
- The use of the ceiling price put forward by the Companies for biomethane, which is based on an efficiency-adjusted cost of electricity, as the avoided cost of gas; and
- The use of a "deemed adder" of 30 percent for non-energy benefits of EEC activity such as job creation and improved human health.

The following will discuss the rationale of the use of the Societal Cost Test in general, before discussing these three proposals in particular.

The Companies have to date employed the TRC test as the primary cost effectiveness screen in establishing EEC programs. While the Terasen Utilities proposed and obtained approval for a portfolio-level TRC approach, the Companies' EEC activity is increasingly expected to support government policy. Government policy incorporates wider goals than just energy savings reflected in the TRC test, such as achieving GHG reductions, or providing programs for low-income customers.

As stated in the 2010 LTRP, we believe that the current cost-benefit criteria for some programs limit the benefits that can be delivered for emission reductions and for certain customer groups such as low income earners.[8] In particular, the Companies' new initiatives described in Section 4 above would not be considered to be cost-effective under the TRC test. The Companies believe, however, that all these programs have merit and that the TRC test does not accurately value the benefits of these initiatives. Continued use of the TRC test has the potential to preclude programs that offer benefits to the public, including customers.

In the 2008 FEI-FEVI EEC Application filed May 28, 2008, the use of the Societal Cost Test was supported by intervenors, as recorded in the Reasons for Decision for Order No. G-36-09 (p. 34). In its Reasons for Decision, the Commission noted the following with respect to the Societal Test:

> *"The Commission Panel acknowledges the Societal test as one which addresses a broader spectrum of factors not included in the TRC test. While recognizing that societal factors have significance, the Commission Panel views many of these factors as being*

[8] 2010 LTRP, page 115.

rather subjective and difficult to measure, The Commission Panel also takes note of the DSM Regulation…requiring the Commission to use, in addition to any other test it considers appropriate, the TRC test in determining whether a demand-side measure is cost-effective."

First, FEU agrees that the Societal Cost Test factors have significance. FEU's fundamental position is that these significant factors must be given some recognition, otherwise some EEC programs will not be permitted to proceed despite offering benefits to the public, including customers.

Second, while FEU agrees that the societal factors may be subjective and difficult to measure, the Companies have set out specific proposals to overcome the difficulties. As explained below, the Companies are proposing a 30 percent deemed adder, which recognizes the significant societal benefits of EEC programs.

Third, the DSM Regulation does not restrict the Commission's ability to use the Societal Cost Test. Section 4(2) of the DSM Regulation only requires the use of the TRC test with respect to demand-side measures specified in section 3(a) of the DSM Regulation, which refers to "a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption". Further, while the DSM regulation requires that the TRC be used for these particular demand-side measures, it does not require that it be the only factor. To the contrary, section 4(2) specifically mandates that the Commission use the TRC "in addition to conducting any other analysis the commission considers appropriate." The Commission is therefore free to use other analysis in considering the cost-effectiveness of even the demand-side measures for low-income households.

The Companies are thus requesting approval to move toward a Societal Cost Test in order to capture some of the benefits associated with the broader goals of DSM. The Companies' particular proposed changes to the benefit/cost screen currently used for EEC activity are discussed below.

5.2.2.1 Use of a 3 percent Social Discount Rate

The discount rate currently being used to evaluate EEC programs is based on the Companies' weighted average cost of capital. Discounting at this rate is not appropriate as energy savings occurring beyond about the 7th year after a measure has been installed are accorded very little value, even though savings may accrue for up to 50 years in the case of some measures such as highly efficient new construction, and building envelope retrofits.

The use of the current discount rate understates the value of EEC measure as 100 percent of the cost of a measure is included in the benefit-cost analysis, but not all of the benefits, since much of the future benefits are so heavily discounted they have no material impact on the TRC result. A more robust analysis would more closely match the benefits of a measure to the costs of the measure. The Companies are therefore proposing the use of a social discount rate of 3 percent to more closely align the benefits associated with a measure with the costs.

5.2.2.2 Use of the Ceiling Price for Biomethane as the Avoided Cost of Gas

The avoided cost of gas currently being used is based upon a forward projection of market costs for conventional fossil fuel-based natural gas. It is used to calculate the "benefit" side of the equation in cost-effectiveness analysis of EEC activity. Because the avoided cost currently being used is based upon market prices, which are subject to volatility and fluctuation over time, the amount of EEC activity that is deemed "cost-effective" also fluctuates with this volatility. This is not a desirable situation given that the Companies' ultimate goal for much of its EEC activity is market transformation, which requires sustained, long-term utility activity in support of increasing market penetration of efficient technology. Moving to the ceiling price for biomethane, which is derived from an efficiency-adjusted cost of "green" electricity, more completely captures the environmental benefits of DSM. Biomethane and "green" electricity are considered to be zero-emission sources of energy; DSM activity is also zero-emission. Thus, using the avoided cost of biomethane or an efficiency-adjusted cost for "green" electricity in the benefit-cost test recognizes the typically higher cost of "green" energy sources such as biogas, electricity and DSM.[9]

5.2.2.3 Use of a "deemed adder" of 30 percent for Non-Energy Benefits

While societal factors/non-energy benefits may be subjective or difficult to measure, they have significance. Not including any benefit for these factors, therefore paints an unduly negative picture of the results of EEC activity. Alongside energy savings, EEC activity creates jobs, offers the opportunity for energy bill savings to be injected back into the economy by customers in the form of other spending, conserves other resources such as water, and can increase human health, comfort and productivity. While the financial value of these additional benefits may be challenging to quantify precisely so that this value can be included in a benefit-cost test, ignoring their value is not appropriate. Thus, the Companies are proposing a "deemed adder" of 30 percent for non-energy benefits be included in the benefit-cost analysis of the Companies' EEC activity. The deemed adder for non-low income EEC activity being proposed by the Companies is aligned with the deemed adder of 30 percent to account for non-energy benefits of low-income programs found in the DSM Regulation for EEC activity for low-income customers.

5.2.3 RECOGNITION OF SPILLOVER EFFECTS IN THE NET-TO-GROSS RATIO

In order to present a more complete view of program impacts, the Companies propose to include in the Net-to-Gross ratio the energy savings attributable to customers undertaking an

9 More information about the ceiling price for biogas can be found on pp 76-77 of FEI's Biomethane Application, dated June 8, 2010.

energy-saving activity who do not participate in a program. This effect is known as "spillover." Both the Net-to-Gross ratio and Spillover are defined below.

> **Net-to-gross ratio (NTG):** The NTG can be a significant driver in the results of TRC, PACT, RIM, and SCT. The NTG adjusts the impacts of the programs so that they only reflect those energy efficiency gains that are the result of the energy efficiency program. Therefore, the NTG deducts energy savings that would have been achieved without the efficiency program (e.g., "free-riders") and increases savings for any "spillover" effect that occurs as an indirect result of the program. Since the NTG attempts to measure what customers would have done in the absence of the energy efficiency program, it can be difficult to determine precisely. [10]
>
> **Spillover (simple definition):** Spillover is the opposite of the free rider effect: customers that adopt efficiency measures because they are influenced by program-related information and marketing efforts, though they do not actually participate in the program.[11]

Although estimating spillover effects is as difficult to determine as estimating free rider effects, it is important to attempt to capture additional energy savings from spillover in order to achieve a more balanced view of program impacts. Thus, the Companies are seeking approval to include spillover effects in Net-to-Gross calculations.

6 CONCLUSION

Subsequent to the approval of FEI's and FEVI's expanded EEC initiatives in 2009, the Province of BC has reaffirmed and strengthened its commitment to energy efficiency and conservation through the enactment of the *Clean Energy Act* ("CEA"). Energy efficiency and conservation, greenhouse gas emission reductions and the promotion of innovative clean energy development in BC are core themes in the CEA. The Companies' EEC proposals and funding requests are aligned with British Columbia's energy objectives as set out in the CEA. The Companies believe that the requested funding for 2012 and 2013 is reasonable as it is supported by the achievable potential identified in the Companies' recently completed Conservation Potential Review.

[10] Source: Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers- Nov 2008
[11] Ibid

- Greenhouse gas reductions
- Reductions for the schools in required emission offset purchases

While boiler upgrades have historically passed the TRC test with a value in the range of 1.0 or greater, closed loop geoexchange systems typically have a standard TRC test result that is less than 1. The Companies have undertaken some analysis of TRCs for Thermal Energy for Schools, based on their experience in the past, and this can be found in the response to BCUC IR 1.201.1.

204.2 What is meant by the phrase "the budgeted $22 million in program spending will employ a pooled approach in the cost-effectiveness evaluations for each school district"? Please explain specifically how the cost effectiveness of these programs will be evaluated.

Response:

By using a pooled approach for a school district, rather than evaluating each school individually, the schools can be combined into one group in order to maximize the benefits (i.e. natural gas usage reductions and GHG emission reductions) for the group while passing the applicable benefit/cost test[47]. The program would be structured to minimize GHG-emissions while ensuring economical solutions through the selection of the optimal combination of technologies to fit within both operating and capital budget constraints of the school district.

The pooled approach has the potential to increase the total number of school retrofits and expand the share of geoexchange installations and associated GHG emission reductions, while keeping incentives to an acceptable level in relation to a school district's combined equipment capital costs.

204.3 If incentives would be available for projects using a third party ownership model, will incentives be offered to private companies who will provide the thermal energy services? To whom would the program incentives be provided?

[47] As indicated in Appendix K, page 12 the EEC New Initiatives do not pass the current TRC test and require changes to the test and / or changes to the DSM Regulation. Without either or both of these changes the Thermal Energy for Schools program will not proceed.

Response:

EEC incentives are provided to natural gas customers to undertake measures to reduce their natural gas consumption. This will be the case regardless of whether the customer retains ownership of the energy system or third party ownership arrangements are in effect. In the case of the Thermal Energy for Schools program, incentives will be provided to the schools boards or schools that are having the qualifying new energy systems installed. The level of the incentives will be the same (assuming that the same energy solution has been undertaken) regardless of whether the schools continue to own and operate their own thermal energy systems or another party such as FEI or another utility owns the system and sells thermal energy to the school(s). In other words, incentives will be available for the projects undertaken by third parties, but the incentives will be paid to the school or school board rather than the private company providing thermal energy services.

FEU is willing to meet with customers and their energy service providers to discuss how EEC funds can be accessed and how customers qualify for these programs.

204.3.1 Are there other companies offering these thermal energy services in BC? If so, why should the FEU ratepayers fund the Thermal Energy for Schools incentives when a competitive market exists?

Response:

Yes, there are other potential providers of thermal energy services for schools in BC. Whether a competitive market exists for providing these services is not relevant to whether an EEC program should or should not be established in the Schools sector. By comparison, many of the FEU's residential and commercial programs are delivered by companies and service providers within the heating and ventilation sector which is comprised of many players and is a highly competitive sector. The purpose of providing EEC incentives is to stimulate incremental energy efficiency and conservation activities by the FEU's natural gas customers and is not dependent on the level of competition that exists among the service providers that will actually install the equipment or carry out the EEC activities.

The basis for the FEU providing incentives to schools and recovering the costs in rates would be the same as for the FEU providing incentives for other EEC programs – they are cost-effective EEC programs that fit within the overall EEC portfolio and assist the Companies in meeting requirements of the DSM Regulation[48].

As indicated above, the purpose of EEC or DSM incentives in general is to stimulate energy efficiency and conservation activity that would not otherwise happen. Incentives are not provided for energy efficiency and conservation activities that would have happened anyway. (In DSM language this is referred to as free ridership where an incentive is provided to a party that would have carried out the DSM activity even with no incentive). The adoption rate for the proposed low carbon thermal energy systems envisioned for the Thermal Energy for Schools program is currently very low. These systems are not being installed with any frequency because of their high initial capital costs and budget constraints within the educational system. The Thermal Energy for Schools program will provide greatly increased opportunities to meet provincial energy objectives in an educational context by promoting the adoption of state-of-the-art low carbon energy solutions.

[48] As noted in Appendix K the Thermal Energy for Schools program and other proposed New Initiatives do not pass the existing TRC test and require changes to the test and/or amendments to the DSM Regulation in order to proceed.

5. Reference: Thermal Energy Projects – EEC Funding

(A) FEU Response to BCUC IR No. 191.4

In the response, FEU states: *As such, all of the programs in the FEU EEC existing and proposed portfolios are demand side management, since they conform with one or more of (a) to (c) above [in the Clean Energy Act.]*

5.1 Does FEU consider all TES projects that it undertakes to fall within the DSM category?

Response:

Demand-side measures and thermal energy services projects are two distinct concepts. A demand-side measure is "a rate, measure, action or program" designed to meet one of the criteria set out in the *Clean Energy Act*. (See Exhibit B-9, Response to BCUC IR 1.191.3.) DSM/EEC funding includes monetary incentives to customers who meet the specific DSM/EEC program criteria, and non-incentive costs such as the funding for the development of a DSM/EEC program. By contrast, thermal energy services projects are FEU-owned assets that deliver thermal energy to customers.

5.2 If the EEC program funding was applied to a TES project undertaken by a third party that met the same criteria except for FEU ownership, would that funding fall within the DSM category?

Response:

Yes. In the FEU's view, ownership of a thermal energy services project should not determine whether incentive funding is DSM. With regard to dispensing EEC incentive funding, it is similarly irrelevant whether the FEU owns or operates a project or not, and as explained in the response to Corix IR 2.5.1, if a customer's initiative qualifies, the customer will receive EEC funding irrespective of asset ownership or their preferred project partner.

5.3 Does FEU agree that the TES projects described in 5.2 would serve the same Clean Energy Act policy objectives if the only difference is third party ownership versus FEU ownership?

building of a green energy project is determined by the customer or developer. An explanation of how EEC funds are provided in the context of circumstances where there may be more than one party (e.g. FEU and Corix) competing for the customer is described in the response to Corix IR 2.5.7.

5.7 Why is it appropriate for FEI to allocate EEC funds to support its TES activities in competing on projects that are awarded through competitive tender?

Response:

This question misrepresents the Companies' approach to making EEC funds available to customers. EEC funds are available to all customers that qualify for an EEC program under that program's terms and conditions, regardless of that customer's choice of ownership model for a project, and regardless of whether a project is awarded through competitive tender and whether the successful candidate to own or operate the facility was the FEU, Corix, or any other third party. The Companies are not, "allocating EEC funds to support TES activities in competing on projects that are awarded through competitive tender", as the Information Request states, and that assertion implies that EEC funds are being allocated directly to the FEU to improve its competitive position vis-a-vis another provider of thermal energy services who would not have access to similar funds. In fact, customers receive the EEC funds, and can use them independent of any third party or to partner with whom they see fit.

(B) Application, Appendix G, page 2.

In the Application, FEU states: *The market interest for Thermal Energy solutions is considerable. FEI currently has over 20 projects in development with a total estimated value exceeding $250 million. Several of these projects are anticipated to be submitted to the BCUC for approval in the near term. Table G-1 provides examples of some of the current Thermal Energy Services projects under development.*

5.8 How many of the "over 20" TES projects in development does FEU expect will receive EEC funding?

5.12 For those projects that started out as FEU EEC initiatives, how did FEU ensure that all the development time and effort was recorded as part of the TES project cost?

Response:

Please refer to the responses to Corix IRs 2.5.10 and 2.5.11.

5.13 How does FEU distinguish between time and effort spent on an EEC project and a TES project?

Response:

Thermal energy services is a class of service within the regulated public utility. By contrast, the EEC activity is within the natural gas class of service, even where the funds are being applied to a thermal energy project, because the EEC funding is promoting conservation and/or the efficient use of energy.

Within FEI there are dedicated employees for each of these activities and hence they charge the majority, if not all, of their time to their respective departments. EEC staff are responsible for developing, designing and operating the FEU's Energy Efficiency and Conservation programs within the FEU's overall EEC initiative. Thermal energy services staff conduct business development and project development activities for the thermal energy class of service. Employees who may work on projects outside their primary line of service allocate their time according to the effort spent on each area of the Companies business on their weekly timesheets.

5.14 Do the employees working on the TES project also charge time to the EEC accounts?

Response:

Please refer to the response to Corix IR 2.5.13.

4.0 Thermal Energy Services for Schools

Reference: 2012/2013 RRA Appendix K Section 4.3 Page 14

"FortisBC is proposing a $22 million incentive program for geoexchange and energy efficiency retrofits in up to 260 schools over two years"

Reference: 2012/2013 RRA - Response to BCUC IR 204.3 & 204.3.1

4.1 Please indicate if, prior to the submission of the 2012/2013 RRA, any FEI staff members, including any member of the designated Thermal Energy Services Group, discussed with any School Districts the possibility of TES EEC funding being approved under the pending RRA. If so, please indicate if any of these discussions took place in the context of FEI or any affiliate developing Thermal Energy solutions for these customers whereby the EEC funding would potentially be used the improve the financial viability of TES projects that would be owned and operated by FEI. Please indicate the number of School Districts (including the total number of schools involved) where these discussions have taken place.

Response:

The FEU are assuming that the "TES" referred to in this question refers to the Companies' proposed Thermal Energy for Schools Program, for which approval has been requested in this Application (Exhibit B-1), and the response to this question is based upon that assumption.

Staff involved in discussions with School Districts do not specifically recall such discussions taking place, but it is generally the case with all of our customers that they are interested in and inquire about available incentives from all sources (whether the utility or government). The FEU sales staff recognize that they are not in a position to make any commitments about EEC funding. Each customer must qualify for EEC funding based on the terms and conditions of the EEC program to which the customer is applying. Moreover, as the proposed Thermal Energy for Schools Program has not yet been approved, the Companies' EEC team has not yet commenced program design for Thermal Energy for Schools, which would include the development of the terms and conditions for a Thermal Energy for Schools Program.

4.2 Please indicate if any of FEI's TES staff is permitted to discuss potential EEC funding that may be available for customers on FEI TES projects or if only designated EEC staff, as part of the regulated natural gas utility, are permitted to have these conversations with customers.

Response:

There are no rules that would preclude thermal energy services staff from discussing EEC funding that may be available for customers on FEI thermal energy services projects. However, as described in the responses to Corix IRs 2.4.6 and 2.5.13, there are different groups of employees that are typically involved in EEC and thermal energy services projects. In any case, EEC funds are provided to customers, not FEI. Competitors of FEI for thermal energy service are also free to discuss any EEC funding that may be available to their customers as well.

4.3 If discussions have taken place with School Districts about the possibility of using EEC funds for FEI Thermal Energy projects, please advise how the levels of EEC funding for each project were arrived at and whether or not these amounts were predicated on the approval of the Societal Test methodology that is part of this RRA.

Response:

Please refer to the response to ESAC IR 2.4.2 regarding the communication of EEC programs.

To date only the Delta School Board has applied for an EEC incentive related to an FEI thermal energy project. The Delta School District's application came through the PSECA program, details of which can be found on pages 74 to 77 of the 2010 EEC Annual Report, filed as Appendix K-4 to Exhibit B-1. The FEU have also corresponded with the Central Okanagan School District specific to one school about the provision of an EEC incentive under the Commercial Custom Design program, which program is detailed on pages 86 – 89 of the 2010 Annual Report, filed as Appendix K-4 to Exhibit B-1 and the FEU expect the School District to apply for the incentive. As the Societal Test methodology is part of the current RRA it has not been used for any calculations other than those included in this and earlier rounds of Information Requests. The proposed Thermal Energy for Schools Program is a new program proposed within this RRA and unless the Societal Test or elements thereof are approved, the proposed Thermal Energy for Schools Program will not go ahead. The EEC team's review of the Delta School District's EEC PSECA incentive application was undertaken using the TRC, as that is the benefit-cost test currently approved for use by the FEU's EEC team.

For an explanation of how the PSECA incentive for the Delta School District was calculated, please refer to the response to ESAC IR 2.6.5.

estimated impact on electricity costs for the DSD? Were forecast future increases in this rate factored into the analysis?

Response:

This question is not relevant to the present proceeding, which is concerned with setting natural gas rates.

6.5 How was the EEC funding for this project calculated? Specifically, how much of the publicly announced $800,000 was from published incentive programs such as the Efficient Boiler Program and how much was based on project-specific or customized incentives?

Response:

The amount of EEC funding available to the Delta School District (DSD) via their application through the Public Sector Energy Conservation Agreement ("PSECA") is not yet final. The amounts that DSD references on their web site, including the reference to $800k of EEC funding, are initial estimates only. As such, the final amount of EEC funding will be determined by FEI and released to the School District upon commissioning and on-site audits of the systems. Current analysis of the project application indicates that approximately $100k of EEC funds will be available to DSD due entirely to the use of high efficiency boiler upgrades at some of the sites.

Any EEC funds that FEI provides to DSD for the thermal plant upgrades will be available through FEU's participation in the PSECA initiative, detailed on pages 74 to 77 of Appendix K-4 to Exhibit B-1. On June 8, 2010, FEI (then Terasen Gas) became a signatory to PSECA, an initiative of the provincial government aimed at reducing energy use and greenhouse gas emissions in public sector buildings. The Companies subsequently developed the PSECA Initiative, to pool investment from the various programs of members including EEC funding, and to streamline the qualification process for projects. Including the DSD, the PSECA initiative provided funding commitments to 10 different organizations for energy efficiency upgrades at 35 separate locations.

The EEC funding becomes available for PSECA applicants such as DSD in the following manner: DSD first submitted an application and detailed energy study to the Climate Action Secretariat ("CAS") for internal CAS review and prioritization. The CAS then forwarded the energy study to the utility PSECA partners (FEI and BC Hydro). FEI reviewed the study to ensure reasonableness of the conclusions, and subsequently submitted each of the proposed energy conserving measures (i.e. the proposed thermal upgrade at each school) to the PSECA Initiative's screening and funding models. Each proposed upgrade was first subjected to a Total Resource Cost (TRC) screening. A portfolio of projects which maintain a TRC score of approximately 1.0 was then selected and incentives for each project developed. Incentives were determined based on the expected stream of natural gas savings. More specifically the incentives were calculated as 5 $/GJ, on the discounted stream of the expected natural gas savings, over 50% of the measure life, up to a maximum of 10 years. This funding model also underlies the upcoming Commercial Custom Design Program, detailed on pages 86 – 89 of Appendix K-4 to Exhibit B-1, and is conceptually similar to other such dollars / GJ saved incentive programs found throughout the country.

6.6 Were the same FEI staff members involved in developing the EAS project with the DSD and determining the EEC incentive amounts?

Response:

No they were not. The project was developed by the Thermal Energy Solutions group within FEI. The Thermal Energy Solutions group at FEI has been working with the DSD for several months to develop a business model and offering that would meet the goals of the customer. Concurrent to this process, the DSD submitted an application for Public Sector Energy Conservation Agreement (PSECA) Initiative for funding for this project. As with all grants or incentives made available in the form of DSM or EEC programs, the customer has a role to play in accessing the programs and meeting the requirements of such programs to qualify for these funds, before the funds can be dispensed.

The PSECA incentive amounts for this project are determined based upon the program parameters, designed and managed by staff on the EEC Team, and described on pages 74 to 77 of Appendix K-4 to Exhibit B-1.

6.7 How much, if any, of the EEC funding for this project was expected to come from the $22 million of school TES EEC funding included in the 2012/2013 RRA?

Habart & Associates Consulting Inc. **Fax**

To:	Sarah Smith / Monika Sewak	**From:**	Jack Habart
Fax:	(604) 592-7618	**Pages:**	2 Including cover sheet
Phone:	(604) 592-7528	**Date:**	24.08.2011
Re:	Habart & Associates	**CC:**	[Click here and type name]

☐ **Urgent** ☐ **For Review** ☐ **Please Comment** ☐ **Please Reply** ☐ **Please Recycle**

Hi Sarah / Monika:

Here is a signed copy of the letter.

Cheers

Jack

Fax: (604) 980-0767
2315 Ennerdale Road
North Vancouver, B.C Canada V7J 3N5
Tel: (604) 980-1828 email: habart@attglobal.net

abart &
Associates
Consulting Inc.

August 24, 2011

Ms Sarah Smith
Manager, EEC
FortisBC
16705 Fraser Highway
Surrey, B.C. V3S 2X7

Re: FortisBC Energy Utilities' Process for Providing Energy Efficiency and Conservation (EEC) Incentives.

Dear Sarah:

By way of background, I have been involved in DSM incentive programs since the late 1980s, and have working with utilities in Canada, the United States and internationally, and find that their approach to administering incentive programs are remarkably similar.

I have been provided with filed responses to Information Requests from the FortisBC Revenue Requirements Application addressing how EEC program funds are distributed to applicants. In particular: Corix IR 2.5.7, 2.6.1-2.6.3 and 2.6.5; ESAC IR 2.5.9. I have also been instructed that FortisBC dispenses incentives as follows:

a) Public utility establishes EEC programs and determines incentive criteria; sets terms and conditions;

b) Public utility informs customers about the EEC programs through different communication channels;

c) Customers identify their EEC needs;

d) Customers complete their EEC improvements/investments;

2315 Ennerdale Road
North Vancouver, B.C
Canada V7J 3N5
Tel: (604) 980-1828
Fax: (604) 980-0767
email: habart@attglobal.net

e) Customers apply for EEC incentives. Applications are reviewed to ensure that the program criteria outlined in the terms and conditions of the EEC program are met;

f) Incentives are distributed to customers.

You have asked me to comment on how this process compares with those used by other utilities with which I am familiar.

This description, and the discussion in the responses to the Information Requests, mirrors the process used by the vast majority of utilities that I have been involved with in Canada, the USA and internationally.

One situation that occurs fairly commonly, especially in the Commercial and Industrial sector, is that the customer will obtain bids from multiple parties to install the EEC measure for them. In some cases the bidder may even operate the facility on behalf of the customer, such as in a Public Private Partnership.

The incentive is made available to the customer who will apply for it regardless of the successful bidder. Further, as the programs and incentives are public knowledge, it is common practice for competing bidders for a project to reference all the incentive programs available for a specific project regardless of whether they are provided by electric utilities, natural gas utilities or various levels of government.

I trust this answers your question.

Sincerely,

Jack Habart
President

NAME: **Jack W. Habart**

EDUCATION: Masters of Business Administration, Simon Fraser University, 1979
Bachelor of Arts, Economics (honours), University of B.C., 1968

OTHER TRAINING: Average 2 weeks per year in technical and management training.

MEMBERSHIP OF PROFESSIONAL SOCIETIES: Association of Energy Service Professionals

EMPLOYMENT:

2001 - Present Habart & Associates Consulting, North Vancouver
Principal

- Consulting focusing on DSM projects for the Canadian and North American market. Major clients include Natural Resources Canada, Terasen Gas and BC Hydro's Power Smart Project. Projects include: development of DSM strategies and plans, often for utilities and agencies who have not undertaken previous DSM work; evaluation of residential, commercial and industrial projects for electric and natural gas impacts; market assessments for electric and natural gas products; end use studies to determine incidence of products, intents to upgrade and segmentation; and business case development for new initiatives. Projects include significant use of primary and secondary market research, and statistical techniques such as discrete choice analysis and conditional demand analysis. Recent work has a strong emphasis on understanding residential & commercial consumer behaviour around energy use.

1995 - 2001 Habart & Associates Consulting, North Vancouver
Principal

- Developed a DSM consulting practice for BC Hydro International Ltd, the consulting subsidiary of BC Hydro and managed projects in the Caribbean, Colombia, Brazil, India, China, the Philippians and Malaysia. Consulting revenues approached $ 1 million per year.
- Consulting specialising in Canadian and international DSM strategy and program development, program management processes including program monitoring and evaluation, utility marketing, and marketing/business development strategy.

1993 - 1995 B.C.Hydro, Vancouver
Manager, Strategic DSM Planning

- Responsible for overall strategic planning for B.C.Hydro's DSM programs. Also provided corporate support such as business cases and discussion papers on strategic issues.

1992 - 1993	B.C.Hydro, Vancouver

1992 - 1993 B.C.Hydro, Vancouver

Manager, Residential Energy Management

- Managed a staff of 20 people who were responsible for design, implementation and operation of residential marketing programs, with an annual budget of $ 18 million.

1988 - 1992 B.C.Hydro, Vancouver

Manager, Planning and Evaluation

- Established program planning and approval management processes for the newly formed Power Smart DSM project, and provided consulting guidance to program managers. Established program evaluation process to ensure that management objectives were being achieved. Participated in the evaluation of initial Power Smart programs evaluation process. Assisted in developing market transformation strategy that included regulations and standards to obtain ongoing savings.

1984 - 1988 B.C.Hydro, Vancouver

Planning Supervisor, Marketing.

- Involved in the planning, operation and monitoring of utility marketing programs including NGV and residential gas load building programs. Developed initial business case for Power Smart and assisted in development of DSM initial programs.

1979 - 1984 B.C.Hydro, Vancouver

Workleader

- Responsible for capacity planning and acquisition of mainframe computer equipment for B.C.Hydro's central computer facility.
- Developed methodology to track and forecast mainframe computer requirements to ensure timely equipment upgrades.

1968 - 1979 IBM Canada Ltd, Vancouver

Technical and Marketing Positions

- Junior marketing representative on a major western Canadian utility account. Introduced reliability management to the account and achieved sales quota.
- Provided Marketing Support for new products and organised planning and training seminars for senior management and field staff.
- Providing technical and marketing support to a number of western Canadian customers.

KEY Projects:
By Client

Terasen Gas – 2001 – Present

- Efficient Boiler Program, Impact Analysis – 2003
- Residential End Use Survey – 2003

    - End Use Survey & Analysis
    - Conditional Demand Analysis
    - Market Segmentation
    - Communications Analysis
    - Upgrade actions and plans
- Residential Heating Program Impact Analysis – 2001, 2002, 2003, 2007
    - Engineering Estimate Analysis
    - Billing Analysis
    - Discrete Choice Analysis
- Fireplace Pilot Program Analysis – 2004
- New Construction Fuel Choice – 2004
- Conservation Potential Review – 2006 (Residential Assist)
- CPR Measure Update – 2007
- DSM Strategy & Program Planning – 2007 (Assist)
- Residential End Use Study, including segmentation – 2008 (Assist)
- Study to understand relative efficiency of n. gas & electric heating – 2009
- Support for codes and standards development that affects natural gas – 2010
- Relative efficiency of natural gas and electricity in residential dwellings
- DSM training for new staff – 2009/10
- Develop DWH strategy

BC Hydro – Power Smart – 2001 – Present

- HEP Internet Audit Evaluation – 2002
- Energy Star Appliance Baseline – 2004
- ECM Furnace Motors Market Assessment – 2004
- Update to ECM Furnace Motors Market Assessment – 2005
- VI Residential Load Shifting – 2004
- Program & Bus. Case Development, Lighting Re-Design – Ongoing
- Business Lighting Baseline – 2006
- Program & Bus. Case Development – Residential New Home – 2005
- Program & Bus. Case Development – PC Power Supplies – 2005
- Market Assessment for Room and Central AC - 2006
- Conservation Potential Review – Behaviour Component – 2006/7
- Update to ECM Furnace Motors Market Assessment – 2008
- Update Behaviour survey – 2008, 2009 & 2010
- Residential new construction practice baseline – 2007 & 2009

Natural Resources Canada – 2001 – 2005

- EnerGuide for Equipment Evaluation – 2002
    - Discrete Choice Analysis
- Dollars to $ense Program Evaluation – 2003

  - Discrete Choice Analysis
- EnerGuide for Houses Evaluation – 2003
  - Discrete Choice Analysis
- Update to Savings from Dollars to $ense Workshops - 2005

Energy Trust of Oregon –2005

- Natural Gas Furnace Market Assessment – 2005

SERVICE IN, AND KNOWLEDGE OF DEVELOPING COUNTRIES:

India	Participation in 3 projects focused on training, DSM strategy in a utility, and assessment of efficiency projects. Worked with a local firm to develop a joint venture in the area of Energy Performance Contracting.
Thailand	Development of DSM policy, strategy and implementation plans for initial programs.
Russia	Review of institution to act as agency for World Bank loans.
Colombia	Led three projects to review DSM policies and activities, and recommend course of action.
Brazil	Project Director and Module Manager for 4 year technology transfer project to assist Procel develop DSM strategies and programs.
Philippines	Reviewed current DSM activities and provided recommendations on how DSM should be incorporated in a proposed restructuring of the sub-transmission system.
Barbados	Manage project to develop the conservation potential, develop initial program strategies and develop business case for DSM in Barbados. Subsequently assisted in the development of a Marketing and Communications group and the development of a Key Accounts program (2003). Assisted in developing Commercial Audit workshop and Hotel EE Update (2007).
Malaysia	Developed and managed a project to assist the utility in Malaysia to assess the opportunities for DSM and to develop a business case and strategy to enter the ESCO business. Assisting a subsidiary of the company, TSPL to develop the ESCO business.
China	Participated in a project to review utility DSM activities and develop a medium term Marketing and DSM plan.
UAE	Participated in a study to determine the potential savings from energy efficiency projects in the Residential Sector in the UAE.

5.7 Why is it appropriate for FEI to allocate EEC funds to support its TES activities in competing on projects that are awarded through competitive tender?

Response:

This question misrepresents the Companies' approach to making EEC funds available to customers. EEC funds are available to all customers that qualify for an EEC program under that program's terms and conditions, regardless of that customer's choice of ownership model for a project, and regardless of whether a project is awarded through competitive tender and whether the successful candidate to own or operate the facility was the FEU, Corix, or any other third party. The Companies are not, "allocating EEC funds to support TES activities in competing on projects that are awarded through competitive tender", as the Information Request states, and that assertion implies that EEC funds are being allocated directly to the FEU to improve its competitive position vis-a-vis another provider of thermal energy services who would not have access to similar funds. In fact, customers receive the EEC funds, and can use them independent of any third party or to partner with whom they see fit.

Request:

6.1 Would the customers of third party utilities such as Corix be eligible for EEC funding if they seek to replace the use of natural gas with eligible alternative energy options, in the same manner as if the eligible alternative energy options were offered by FEU. If not, please explain.

<u>Response:</u>

Yes they would, as noted in the response to BCUC IR 1.204.3, quoted in the preamble above.

6.2 Explain the incentives that would be available to a school board using a third party TES project ownership structure and those that would not.

Response:

To reiterate, EEC incentives are available to all customers that qualify for any program under that program's terms and conditions, regardless of project ownership. FEU EEC Principle 1, laid out in the Companies' original EEC Application on page 47 states:

> *"Programs will have a goal of being universal, offering access to energy efficiency and conservation for all …customers…"*

The Companies' EEC activity is governed by the EEC Program Principles; the principle of universality put forward by the Companies in 2008 means that all eligible customers that comply with the terms and conditions of any given program can participate in that program.

As the funding envelope for the proposed Thermal Energy for Schools Program has not yet been approved, and program planning and design have not yet commenced, detailed information about incentives available and how customers qualify cannot be provided at this time.

If the funding for this program area is approved, the next steps would be to do detailed design of the program and to communicate the program to customers through a variety of channels.

6.3 Would the incentive described in 6.2 be available if Corix was the third party TES project owner? If not, please explain.

Response:

Yes. Regardless of the project, all EEC incentives are available to all customers that qualify for a program under that program's terms and conditions.

6.5 Does unequal access to the EEC funding – i.e. preference or exclusive access to FEU TES projects – give FEU a competitive advantage in the TES market? Explain.

<u>Response:</u>

The hypothetical scenario as posed in this Information Request does not reflect the FEU's practice. The FEU make all EEC funding available to customers that meet EEC program criteria, without preference, and the same policy will be applied in respect of any future program designed to support thermal energy services regardless of whether the provider of the thermal project is the FEU, Corix, or another third party.

5.9 Please indicate the relationship between the FEI staff that are developing these projects with school district customers and the FEI staff responsible for approving and distributing EEC funds under the High Efficiency Boiler program.

Response:

The staff involved in developing projects for school district customers are distinct from those that distribute EEC funds under the High Efficiency Boiler program.

The FEU staff that develop the thermal energy solution projects are in the Thermal Energy Solutions group, reporting to the Director, Business Development. The FEU staff responsible for administering the Efficient Boiler Program are in the EEC group, and in the Energy Products and Services group, reporting to the Director, Resource Planning and Market Development. Once an application for participation in the Efficient Boiler Program is received from a customer, it is reviewed by the Energy Products and Services Group. Then the application is forwarded to the EEC group, which ensures that all terms and conditions for the program are met, including that qualifying equipment has been installed, and issues the rebate cheque to the customer based on the program funding formula. All program details for all programs are available on the FEU's website, www.fortisbc.com. The Thermal Energy Solutions group staff that might be involved in developing the actual thermal energy projects with a customer that would be a potential recipient of EEC incentive program funds, should that customer choose to work with the FEU, are not involved in the process of designing EEC programs including program terms and conditions, nor are they involved in approving customer incentive funding applications to EEC programs.

Appendix H

BCUC Decisions

1. CNG-LNG Decision (G-128-11)
2. EEC NGV Incentive Decision (G-145-11)
3. Biomethane Decision (G-194-10)
4. 2010-2011 TGI RRA (G-141-09)
5. 2010-2011 TGVI RRA (G-140-09)
6. 2008 EEC Decision (G-36-09)
7. 2008 Long Term Resource Plan Decision (G-194-08)
8. 2010 Long Term Resource Plan Decision (G-14-11)

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER** G-128-11

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

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

and

An Application by FortisBC Energy Inc.
for Approval of a Service Agreement for Compressed Natural Gas Service
with Waste Management of Canada Corporation
and
General Terms and Conditions for
Compressed Natural Gas and Liquified Natural Gas Service

BEFORE: A. A. Rhodes, Panel Chair/Commissioner
D. A. Cote, Commissioner July 19, 2011
D. Morton, Commissioner

O R D E R

WHEREAS:

A. On December 1, 2010, FortisBC Energy Inc., formerly Terasen Gas Inc. (FEI), applied to the British Columbia Utilities Commission (Commission) for approval of a Service Agreement with Waste Management of Canada Corporation for compression and dispensing service for Compressed Natural Gas (the Waste Management Agreement), pursuant to sections 59 to 61 of the *Utilities Commission Act* (the Act);

B. FEI also applied for acceptance of the expenditures required to provide compression and dispensing service for Compressed Natural Gas under the Waste Management Agreement pursuant to section 44.2 of the Act;

C. FEI also applied for approval of General Terms and Conditions for compression and dispensing service for Compressed Natural Gas (CNG) Service and transportation, delivery, fuel storage and dispensing service for Liquified Natural Gas (LNG) Service for inclusion in future service agreements with customers pursuant to sections 59 to 61 of the Act, (collectively, the Application);

D. FEI sought an expedited process for approval of the Waste Management Agreement, requesting a permanent rate on or before January 14, 2011, or, alternatively, approval of an interim rate pursuant to section 89 of the Act on or before that date;

E. By Order G-181-10 dated December 6, 2010, the Commission established an expedited written hearing process for its consideration of the Waste Management Agreement, and established a written hearing process for the remainder of the Application;

F. By Order G-6-11 dated January 14, 2011, the Commission approved the Waste Management Agreement on an interim basis, subject to certain changes; and subject to an amended version being refiled with the Commission in standard Tariff Supplement form on a non-confidential basis;

G. On March 25, 2011, FEI submitted the amended Waste Management Agreement as Tariff Supplement J-1;

H. The Commission has considered the evidence and submissions of the parties and approves the interim Waste Management Agreement in final form as a Tariff Supplement. The Commission also accepts the expenditures on the facilities required to provide service under the Waste Management Agreement pursuant to section 44.2 of the Act but rejects the proposed General Terms and Conditions. The Commission will approve revised General Terms and Conditions which better provide for full cost recovery from the potential CNG/LNG customer, as set out in the Reasons for Decision which follow.

NOW THEREFORE pursuant to sections 44.2, 59-61, and 90 of the Act, and for the Reasons contained in Appendix A hereto, the Commission orders as follows:

1. The Waste Management Agreement as amended and refiled on March 25, 2011 as Tariff Supplement J-1, is approved in final form.

2. The expenditures required for FEI to provide compression and dispensing service for natural gas under the Waste Management Agreement, in the amount of $775,031 are accepted.

3. Approval of the proposed General Terms and Conditions for CNG Service and LNG Service is denied.

4. The Commission will approve revised General Terms and Conditions which, in addition to the proposed "Take or Pay" commitment, better reflect full cost recovery from the potential CNG/LNG customer, as more fully set out and explained in the Reasons for Decision attached hereto as Appendix A.

5. FEI shall comply with all directions of the Commission Panel in the Reasons for Decision attached hereto as Appendix A.

6. Subject to FEI filing revised General Terms and Conditions acceptable to the Commission, depreciation rates are approved in accordance with the following table:

Asset	Estimated Useful Life (years)	Depreciation Rate (%)
CNG Dispensing Equipment	20	5%
LNG Dispensing Equipment	20	5%
Foundations	20	5%
Pumps	10	10%
Dehydrator	20	5%

7. No amounts will be approved for capitalized overhead.

8. The following deferral accounts are approved:

   a. A non-rate base deferral account attracting AFUDC to capture the cost of the current application, including the cost of the Waste Management Application and to recover these costs from all non-by-pass customers by amortizing them through delivery rates commencing January 1, 2012 over a three year period. [Future individual application costs must be recovered from those customers.]

   b. A non-rate base deferral account attracting AFUDC to capture the O&M costs and the cost of service associated with the capital additions to the delivery system incurred and the CNG and LNG Service recoveries received prior to January 1, 2012 for contracts approved by the Commission, and to recover or refund the balance to all non-bypass customers by amortizing the balance through delivery rates commencing January 1, 2012 over a three year period.

   c. An ongoing rate base deferral account to capture incremental CNG and LNG recoveries received from actual volumes purchased in excess of minimum contract take or pay commitments to be refunded to all non-bypass customers by amortizing the balance through delivery rates over a one year period, commencing the following year, to be effective as of January 1, 2012 pursuant to sections 59 to 61 of the Act.

DATED at the City of Vancouver, in the Province of British Columbia, this 19th day of July, 2011.

BY ORDER

Original signed by:

A.A. Rhodes
Panel Chair/Commissioner

Attachments

IN THE MATTER OF

FORTISBC ENERGY INC.
AN APPLICATION FOR APPROVAL OF A SERVICE AGREEMENT
FOR COMPRESSED NATURAL GAS SERVICE
WITH WASTE MANAGEMENT OF CANADA CORPORATION
AND GENERAL TERMS AND CONDITIONS FOR COMPRESSED NATURAL GAS
AND LIQUEFIED NATURAL GAS SERVICE

REASONS FOR DECISION

JULY 19, 2011

BEFORE:

A.A. Rhodes, Panel Chair / Commissioner
D.A. Cote, Commissioner
D. Morton, Commissioner

TABLE OF CONTENTS

APPENDICES

EXECUTIVE SUMMARY

In December, 2010, FortisBC Energy Inc. (FEI) applied to the British Columbia Utilities Commission (Commission) for approval of "General Terms and Conditions" to allow it to offer Compressed Natural Gas (CNG) and Liquified Natural Gas (LNG) fuelling service to various potential customers with return to base fleets of buses, heavy duty and vocational trucks. Vehicles in these fleets are currently fuelled, for the most part, by diesel and would be converted, or replacement trucks purchased, to run on CNG or LNG. FEI proposes to negotiate individual agreements with customers to construct and operate a fuelling facility on their premises. Each agreement will reflect the proposed General Terms and Conditions, but may include additional provisions that reflect the specific terms that have been negotiated. While FEI proposes to recover most costs of the natural gas vehicle (NGV) fuelling infrastructure from new CNG/LNG customers, the Panel finds that there are still what could amount to substantial potential costs that are proposed to be recovered from existing ratepayers.

FEI also sought acceptance of the forecast expenditures it incurred to provide a fuelling station to Waste Management of Canada Corporation (Waste Management) and approval of the draft contract between those two parties. This contract (the Waste Management Agreement) is the first specific instance of a contract based on the proposed General Terms and Conditions. On January 14, 2011 the Commission agreed to approve the Waste Management Agreement on an interim basis provided certain changes were made and the amended agreement was filed on a non-confidential basis. The revised Waste Management Agreement was filed in final form as Tariff Supplement J-1 on March 25, 2011. The Commission Panel now approves the Waste Management Agreement as a Tariff Supplement. It also accepts the expenditures for FortisBC Energy Inc. to construct the fuelling facilities at Waste Management's premises.

The Panel finds that if the NGV market can be developed as described in FEI's application, benefits would accrue to FEI's new NGV customers, its existing ratepayers and the residents of British Columbia, not to mention FEI itself. These benefits arise from the lower cost of natural gas as a fuel when compared to diesel or gasoline; the increased throughput of natural gas on the FEI system due to the additional consumption of the truck fleet, other things equal, and the reduction in Green House Gas (GHG) emissions from the use of natural gas as compared to diesel or gasoline. However, the Panel finds that there are significant risks associated with this venture, including, but not limited to, the uncertainty surrounding the future price spread between natural gas and oil, and the apparent need for ongoing incentive funding to subsidize the higher cost of natural gas engines. These two factors, among others, had both contributed to the collapse of a previous NGV market in BC in which the Applicant had been involved.

Further, the Panel finds that a CNG/LNG fuelling infrastructure has no natural monopoly characteristics and the service offerings applied for would not be subject to regulation, unless the services were being provided by an organization that is already a regulated public utility.

Thus, the Panel finds that, given the risks involved and the potential presence of unregulated competition in the NGV market, it is neither in the public interest nor fair and just that FEI's existing ratepayers subsidize the NGV fuelling facilities. The Panel is of the view that the major beneficiaries of this proposed project are the potential new customers in the transportation sector, who are GHG emitters, FEI itself, which will make a return on the fuelling station infrastructure, and the residents of the province as a whole, who will enjoy reduced GHG emissions. FEI's existing ratepayers, on the other hand, may enjoy some reduction to the delivery charge they are required to pay due to increased throughput on the system, other things equal, but are not otherwise beneficiaries to the same extent, although they are being asked to shoulder the risks, should the project be unsuccessful. Accordingly, the Panel rejects the proposed General Terms and

Conditions as too general and failing to ensure that the actual cost of service is collected from the customer, as fully as possible. The Panel will approve revised General Terms and Conditions which reflect a greater recovery of the total actual cost of service as outlined in these Reasons for Decision.

1.0 INTRODUCTION

On December 1, 2010 FortisBC Energy Inc., formerly Terasen Gas Inc., applied to the Commission for, among other things, expedited approval of an executory contract to provide natural gas compression and dispensing services to Waste Management of Canada Corporation (the Waste Management Agreement). This was approved for as a Tariff Supplement pursuant to sections 59-61 of the *Utilities Commission Act*, R.S.B.C. 1996, c.473, as amended, for its fleet of return-to-base natural gas vehicles (NGVs).

The Waste Management Agreement was approved on an interim basis on January 14, 2011 (subject to certain amendments and the requirement it be filed on a non-confidential basis), to allow for a closer examination of the business model and any implications which could arise as a result of its approval.

In this Application, FEI also seeks the following:

- permanent approval of the now final Waste Management Agreement as a Tariff Supplement pursuant to sections 59 to 61 of the *Utilities Commission Act (*alternatively, *UCA* or the *Act*).
- acceptance of the expenditures it made on the facilities required to provide the natural gas compression and dispensing services to Waste Management under s. 44.2 of the *Act*.
- approval of standard form "General Terms and Conditions" pursuant to sections 59-61 of the *Act* to allow FEI to offer natural gas vehicle services to other potential customers for:
    - compression and dispensing services for Compressed Natural Gas (CNG); and
    - transportation, delivery, fuel storage, and dispensing for Liquified Natural Gas (LNG).

FEI takes the position that the approvals sought in the Application will benefit existing customers by enabling the addition of cost-effective load to the natural gas distribution system. However, it acknowledges that ratepayers should bear little or no risk and be "kept whole". It submits that the "take or pay" provision, which is a cornerstone of the business model, "ensures that the customer carries the bulk of the cost and risk associated with the investment." (Exhibit B-1, pp. 11, 13)

2.0 SPECIFIC ORDERS SOUGHT

FEI seeks the following specific approvals:

1. An Order approving the Waste Management Agreement pursuant to sections 59-61 of the *Act*.
2. An Order accepting the estimated expenditures (in the amount of $737,944) for the Waste Management project pursuant to s. 44.2 of the *Act*.

3. An Order approving an amendment to FortisBC Energy's "General Terms and Conditions," specifically, the addition of a new section 12B relating to CNG and LNG Service.

4. An Order approving:

   a. Depreciation rates applicable to NGV refuelling assets as per the following table:

Asset	Estimated Useful Life (years)	Depreciation Rate (%)
CNG Dispensing Equipment	20	5%
LNG Dispensing Equipment	20	5%
Foundations	20	5%
Pumps	10	10%
Dehydrator	20	5%
Capitalized Overhead	Average	2.7%

   b. A non-rate base deferral account attracting an Allowance for Funds Used During Construction (AFUDC) to capture the NGV Fuelling Service Application costs incurred in 2010 and 2011 and to recover these costs from all non-by-pass customers by amortizing them through delivery rates commencing January 1, 2012 over a three year period.

   c. A non-rate base deferral account attracting AFUDC to capture the operating and maintenance costs and the cost of service associated with the capital additions to the delivery system incurred and the CNG and LNG Service recoveries received prior to January 1, 2012, and to recover or refund the balance to all non-bypass customers by amortizing the balance through delivery rates commencing January 1, 2012 over a three year period.

   d. An ongoing rate base deferral account to capture incremental CNG and LNG recoveries received from actual volumes purchased in excess of minimum contract take or pay commitments to be refunded to all non-bypass customers by amortizing the balance through delivery rates over a one year period, commencing the following year, to be effective as of January 1, 2012 pursuant to sections 59 to 61 of the *Act*.

(Application, pp. 57, 70-71)

3.0 PROCEDURAL BACKGROUND

The Application was heard by way of a two stage written hearing process, to allow the application for approval of the Waste Management Agreement to proceed on an expedited basis. Three rounds of Information Requests in total were conducted. A number of the Information Requests were also sought to be held confidential. Some responses were refiled on a non-confidential basis. Where possible, the Commission Panel makes reference only to non-confidential information. However, in some instances, reference to confidential information cannot be avoided. The Commission Panel has attempted to ensure that reference has not been made to information which might be considered "commercially sensitive."

The following parties intervened: B.C. Sustainable Energy Association (BCSEA), B.C. Old Age Pensioners' Organization (BCOAPO) and the Commercial Energy Consumers (CEC). The hearing concluded with the filing of FEI's Reply Submissions on April 12, 2011.

4.0 HISTORICAL BACKGROUND

FEI, through one or more predecessor companies, has previously been involved in the NGV market. It was initially successful in penetrating the light duty vehicle market some decades ago when it established a public CNG fuelling network as a regulated offering. However, this network proved to be unsustainable when market conditions changed. (Exhibit B-1, p. 8)

More specifically, during the mid 1980s to 1990s FEI installed, owned and maintained CNG compression facilities at numerous sites as a regulated offering. At that time, FEI's focus was on public fuelling stations where the retail companies which hosted the CNG fuelling stations were charged a postage stamp rate. Vehicles utilizing the service were primarily high-mileage light duty converted vehicles.

In 1991, in BC, there were over 30 NGV fuelling stations to serve over 7,000 NGVs. Consumption of natural gas by the transportation sector peaked in 1992. At that time there was a wide price differential between natural gas and gasoline, supporting the market. FEI reports that by 1997 there were 52 fuelling stations (owned and operated either by its predecessor company or a third party provider) within its service territory, with an annual load of 627,000 GJ. By the late 1990s car manufacturers had started manufacturing NGVs and these vehicles became more prevalent than converted vehicles. (Exhibit B-1, p. 9)

On December 15, 1999, FEI, then Terasen, applied to the Commission for permission to sell its NGV utility assets to a wholly-owned non-regulated subsidiary, now known as Clean Energy. At that time, Terasen had compression and dispensing equipment located at 19 sites with a net book value of $4.1 million. The compression and dispensing service had been losing money and was being supported by other customer classes. The sale of the equipment, effective January 1, 2000, resulted in a loss of $2.13 million which was to be amortized over ten years and borne by ratepayers. The $2.13 million charge represented just over 50% of the net book value of the assets. (Exhibit B-6, BCUC IR 2.6.1) FEI takes the position that it formed the "separate, non-regulated company in order to have greater flexibility to grow the NGV market and own and operate natural gas fuelling stations across North America." (BCUC Order G-143-99; Exhibit A-2-4; Exhibit B-1, p. 9)

FEI sold what remained of its interest in Clean Energy in 2005. (Exhibit B-6, BCUC IR 2.29.2) At this point in time, "...the light-duty NGV market has almost completely eroded in B.C." Service has historically been provided by FEI to the transportation sector primarily under Rate Schedule 6. Rate Schedule 6 also offers up to $10,000 in incentive funding for the purchase of a factory-built NGV or the conversion of a conventionally-fuelled vehicle to natural gas. Rate Schedule 25 is also available for the provision of natural gas to large general accounts. This rate schedule had one customer, being Coast Mountain Bus Company, at the time the Application was prepared. (Exhibit B-1, Appendix A-2, pp. 8, 11-12; Appendix C, Rate Schedule 6)

FEI attributes the decline in consumption of natural gas by light duty vehicles over the last decade to a number of factors including:

- The price spread between natural gas and conventional fuels narrowed in the period between 2001-2003 to the point where there was no longer a sufficient economic incentive to switch to natural gas, given the difference in capital costs for the two options;
- Circa 2004 car manufacturers withdrew NGV offerings of pickup trucks and vans from the market;

- The cost of engine conversions increased from $3,000 (early 1990s) to $7,000 to $10,000 (now);
- A Natural Resource Canada matching grant program incentive for vehicle conversions was discontinued in 2006;
- Hybrid vehicles were introduced and competed with passenger and light duty vehicle market segments; and
- With load loss, stations closed and fuelling became less convenient.

(Exhibit B-1, pp. 9-10)

5.0 MARKET CONDITIONS, GOVERNMENT POLICY AND THE NEED TO KICKSTART THE NGV MARKET

Vehicles fuelled by natural gas, either in CNG or LNG form, although less energy efficient than their diesel counterparts, produce less Green House Gas (GHG) emissions. (Exhibit B-8, BCSEA IR 2.3.1) FEI advises that studies have shown conventional CNG has a net carbon intensity which is lower than that of reformulated gasoline and 28% less than that of ultra-low sulphur diesel; and that LNG provides a comparable reduction. (Exhibit B-1, p. 37) Thus, FEI argues that the displacement of vehicles currently fuelled by gasoline or diesel with vehicles fuelled by natural gas would result in significant reductions in GHGs in British Columbia. However, natural gas is not without GHG emissions. [A Gigajoule (GJ) of natural gas produces in the range of .05069 tonnes of GHGs, as per Terasen Gas Inc. 2010-2011 Revenue Requirements Application, Response to BCUC IR 1.22.1] In the case of Waste Management, FEI estimates that its fleet of twenty heavy duty vehicles would create 921.6 tonnes of carbon per year when run on diesel as compared to 708.2 tonnes of carbon per year when run on CNG, a saving of 213.4 tonnes per year, based on an analysis using GHG emissions per kilometres travelled for the two fuels. (Exhibit B-8, BCSEA IR 2.3.1)

FEI maintains that this reduction in GHG emissions can assist the province in meeting some of the objectives of the 2007 Energy Plan and the *Clean Energy Act* and notes that the Energy Plan identified the transportation sector as "a major contributor to climate change and air quality problems." (Exhibit B-1, pp. 35-36) FEI also notes that the Low Carbon Fuel Requirements Regulation mandates a 10% reduction in carbon intensity of motor fuels in BC by 2020.

FEI submits that in spite of the recent near collapse of the market for NGVs, there is currently a significant upside potential to this same market. Specifically, it forecasts that by 2030, there is the potential for 30 Petajoules (PJs) of natural gas energy use for buses, medium and heavy duty trucks; and an additional 6 PJs of demand for passenger vehicles. (Exhibit B-1, p. 23) [This compares to the total amount of natural gas delivered in the FEI system in 2010 of approximately 200 PJs]. FEI cites a number of factors that may contribute to the growth in demand for NGV over the next 10 to 20 years, including:

- Natural Gas price advantage over diesel which translates to operating cost savings;
- Competitive advantage of natural gas over diesel due to environmental benefits, including ownership and value of carbon credits;
- Availability of fuelling infrastructure; and

- Incentive funding that will reduce the incremental cost of manufactured NGV vehicles over diesel/gasoline powered vehicles.

(Exhibit B-1, pp. 25-33)

FEI submits that market indications are that natural gas is likely to retain its price advantage over diesel for the foreseeable future. (FEI Final Submissions, para. 35) FEI recognizes, however, that "predicting market share for alternative energy technologies is extremely difficult and highly subjective. Historically, projections for rapid adoption rates have proved to be wildly optimistic." (FEI Response to BCUC IR 2.68.3 from 2010-2011 RRA Application filed as Exhibit A2-6)

FEI is hoping to "kickstart" the potential market for natural gas vehicles with a regulated CNG compression and dispensing service and a storage and dispensing service for LNG. It maintains that because it is in the business of delivering energy to customers in a useable form these services are natural extensions of its existing service to customers. It further states that extension tests and policies are used to ensure that new customers pay the cost of service. (Exhibit B-1, p. 19)

FEI argues that the NGV business model being proposed is different from its previous venture, in that it targets return-to-base fleets of buses, heavy duty and vocational trucks which can be manufactured to use natural gas (as opposed to requiring conversion) and are available in British Columbia. It further argues that although the target market is smaller, there is less risk of changing market conditions. (Exhibit B-1, p. 10) These fleets of vehicles will serve as "anchor tenants" for the customized fuelling stations which FEI will build and own on the customer's premises. The vehicles can be fuelled on their return to their base each evening, giving FEI what amounts to a committed "captive audience."

FEI is proposing a rate design that is based on the cost of service. Once the market is more mature, FEI states that it may consider other rate designs and business models. It submits that the approach being put forward in this Application "will allow for the safe, economic and timely development of additional NGV projects to ensure that demand for NGV and supply of NGV Services are re-introduced in a sustainable manner." (Exhibit B-1, p. 20)

6.0 PROPOSED BUSINESS MODEL

6.1. CNG Service Description

FEI's target market for the CNG service offering will be buses and heavy duty or vocational trucks that are return-to-base fleets which are of sufficient size to be readily served by original equipment manufacturers' (OEM) product. In providing its service offering, FEI has identified three required steps in what it describes as the CNG value chain or model. The first step is the physical delivery of the natural gas supply to the customer. Once delivered, the second step is the process of compressing and storing natural gas at high pressure to be ready for delivery to the vehicle's storage tank. Accordingly, FEI will build customized, private stations designed to support the particular customer's return-to-base fleet with the capability of pressurizing fuel at up to 3,600 pounds per square inch (psi). The third step in the chain involves the actual dispensing of the CNG to the vehicle. FEI states that the cost of owning and maintaining the station for compression and dispensing will be part of the cost of service (COS) and the customer will be responsible for paying a per GJ charge which includes these costs.

With this model FEI states it will be positioned to offer the complete CNG service offering to potential customers. This will involve the following:

- Execution of a service agreement with the customer for compression and fuelling services;
- Investment in any required meter and main extensions and provision of the gas supply; and
- Installation and maintenance of the compression, pressure storage and dispensing equipment.

It is FEI's plan to own and maintain the private station equipment which includes gas compressors, gas dehydrators, high pressure storage tanks and fuel dispensers. Fuel dispensers may be either of the "fast-fill" type [as used in the case of BC Transit] which can fuel a vehicle in 2-3 minutes, or a time-fill setup which can be used to refuel a vehicle overnight, or a combination of the two. (Exhibit B-1, pp. 14-16)

6.2 LNG Service Description

LNG is natural gas which has been cooled to -160 degrees Celsius and must be stored on vehicles and in stations at this low temperature if it is to remain in a liquid state. FEI states that this fuel, because of its density, is particularly well-suited for vehicles like highway tractors with high daily mileage requirements. Like CNG, the value chain for LNG involves a number of steps. The first of these is the production and initial storage of LNG which is currently done at FEI's Tilbury bulk LNG storage facility. The second step in the chain involves the delivery of LNG for use in a customer's fuelling station since there is no piped infrastructure for LNG. FEI states that its proposed LNG service offering contemplates FEI owning and operating the transport and delivery process although it will allow customer delivery of the LNG where appropriate. The third step in the value chain involves the fuel storage and dispensing at the customer fuelling station - services which again FEI will provide.

As with the CNG model, FEI anticipates that it will be positioned to provide a complete LNG service offering to the customer. This will involve the following:

- Provision of LNG supply at Tilbury (where it is offered for bulk sale under Rate Schedule 16 – which is an interruptible service currently offered pursuant to a 5 year pilot project);
- Securing a service agreement with the customer for the LNG fuelling station (including cryogenic storage and dispensing);
- LNG transport from Tilbury to the customers' facility by transport truck, if required; and
- Investment in and maintenance of the storage and dispensing equipment.

For the LNG Service offering, it is FEI's intention to own and maintain the LNG tankers, cryogenic storage tanks which include secondary containment, the LNG vaporizer and pump and the dispenser equipment. As with the CNG offering, the model calls for the cost of owning and maintaining the station to be built into the COS charge which will be recovered from the customer on a per GJ basis. Where required, a separate delivery charge to cover transport and delivery of the LNG will be created. (Exhibit B-1, pp. 16-18)

6.3 Rate Schedules

FEI's business model is reflected in the rate structures for which it seeks approval. Essentially, there are two components:

1) the General Terms and Conditions for CNG and LNG Services; and

2) Customer-Specific contracts, which will be filed as Tariff Supplements.

In this Application, FEI is seeking Commission approval of standard form General Terms and Conditions which incorporate its proposed rate design for both CNG and LNG service pursuant to sections 59-61 of the *Utilities Commission Act,* which deal with rates. This proposed rate design "yields a customer-specific rate that will be incorporated into the applicable service agreement." (Exhibit B-1, p. 61)

FortisBC proposes that the General Terms & Conditions will have the following:

- a take or pay provision;
- provisions for full cost recovery from each customer; and
- stipulation of how the cost of service will be determined.

The General Terms and Conditions for which approval is sought are contained in Appendix B of the Application. They are an amendment to FEI's General Terms and Conditions by way of the addition of a section (section 12B) which relates to CNG and LNG Service. (Application, p. 11) Section 12B is very general and comprises little more than a single page. It is reproduced in its entirety in Appendix 1 of these Reasons for Decision.

Section 12B.3 deals with Cost of Service Recovery. This section states:

> "Customers will be charged a "take-or-pay" rate (i.e. minimum contract demand) under the Service Agreement that recovers the present value of the forecast cost of service associated with the provision of CNG or LNG Service over the term of the Service Agreement, where the minimum contract demand is the forecast consumption based on the forecast number of vehicles served by the vehicle fueling station."

Section 12B.5 Costs states:

> "The total costs to be used in determining the forecast cost of service to be recovered from the Customer under the Service Agreement include, without limitation
>
> (a) the capital investment, including any associated labour, material, capitalized overhead and other costs necessary to serve the Customer, less any contributions in aid of construction by the Customer or third parties, grants, tax credits or non-financial factors offsetting the full costs that are deemed to be acceptable by the British Columbia Utilities Commission

(b) depreciation expense related to the capital assets associated with the vehicle fuelling station; and

(c) the incremental operating and maintenance expenses necessary to serve the Customers.

In addition to the costs identified, the cost of service recovery will include applicable property and incomes taxes and the appropriate return on rate base approved by the British Columbia Utilities Commission."

6.4 Cost of Service Model

FEI advises that, at a high level, the cost of service model captures all of the costs associated with providing service to a particular NGV customer, and uses those costs to generate a rate which recovers the cost of serving that specific NGV customer over the term of the agreement. (Exhibit B-1, pp. 11-12)

6.1.1 "Take or Pay" Commitment

Each customer-specific service agreement will contain a "take or pay" commitment which will require the customer to commit to purchase a specified volumetric fuel charge, calculated to recover the cost of service, whether or not such volume is actually required or consumed. However, if the customer takes more service than the amount committed to, an excess rate will be charged, which may be less than the "take or pay" rate. (Exhibit B-1, p. 12) FEI proposes to accumulate any additional revenues from quantities purchased in excess of the minimum committed "take or pay" volume in an ongoing rate base deferral account, commencing in 2012. (Exhibit B-1, p. 71)

6.1.2 Cost of Service Calculation

FEI proposes to base the cost of service calculation on the total forecast – as opposed to actual - costs to provide either CNG or LNG service which include:

- The capital cost of the fuelling station – including any associated labour, materials, capitalized overhead, less any contributions in aid of construction, grants etc. offsetting the full cost;
- Incremental operating and maintenance costs necessary to serve the customer;
- Depreciation expense related to the capital assets associated with the contract;
- Applicable property tax;
- Calculated income tax expense;
- Return on rate base at the then-current approved rate.

(Exhibit B-1, p. 55)

6.1.3 Capital Costs

FEI proposes to use forecast capital costs as an input into its cost of service calculation. It submits that its forecast costs have a high degree of accuracy for the following reasons:

- It has undertaken "detailed and comparative quotations";
- Its project engineering team is experienced;
- The fuelling station, which represents the largest component of a project's costs, can be procured by way of a fixed price contact.

The forecast capital costs also include capitalized overhead. Capitalized overhead is calculated as 14% of forecast gross operating and maintenance costs. (Exhibit B-1, p. 56)

6.1.4 Operating and Maintenance Costs

Forecast operating and maintenance (O&M) costs represent the incremental material and labour expenses associated with maintaining each fuelling station as well as the incremental administrative costs associated with each contract. FEI expects, however, that any administrative costs will be minimal, as most candidates for CNG or LNG service will be existing customers. O&M costs are estimated to be in the range of 4% to 6% of the capital costs for an LNG project. (Exhibit B-6, BCUC IR 2.10.2; 2.10.4) The gross forecast operating and maintenance costs will also be reduced by the 14% amount attributed to capitalized overhead.

FEI increases the net forecasted operating and maintenance expenses in its cost of service model by 2% per annum. (Exhibit B-1, p. 57) However, FEI also proposes that this escalation factor be open to negotiation with the individual customer. (Exhibit B-1, p. 61)

6.1.5 Depreciation and Amortization Expense

FEI proposes to use depreciation rates which, other than capitalized overhead, represent recovery of the cost of the asset over its estimated useful life, which is, for the most part, 20 years. (Exhibit B-1, p. 57) FEI proposes to amortize capitalized overhead at the rate of 2.7% per annum, which equates to a 37-year period.

The following table sets out the depreciation rates for which approval is requested:

TABLE 1
Useful Life and Resulting Depreciation Rates for CNG and LNG Fuelling Assets

Asset	Estimated Useful Life (years)	Depreciation Rate (%)
CNG Dispensing Equipment	20	5%
LNG Dispensing Equipment	20	5%
Foundations	20	5%
Pumps	10	10%
Dehydrator	20	5%
Capitalized Overhead	Average	2.7%

Source: Exhibit B-1, p. 57, Table 5-1

6.1.6 Property Taxes

As property taxes are site-specific, the property tax expense forecast will vary by project. The forecast property tax is an input to the cost of service calculation. (Exhibit B-1, p. 58)

6.1.7 Income Taxes

FEI also proposes to include forecast income taxes expense, calculated on an estimated actual taxes payable basis, in its cost of service calculation. (Exhibit B-1, p. 58)

6.1.8 Rate Base and Earned Return

FortisBC Energy's cost of service will also include an amount for the allowed return on the rate base associated with each CNG or LNG contract. (Exhibit B-1, pp. 60-61)

6.1.9 Contract Term

At a minimum, FortisBC proposes to match the contract term to the life of the initial fleet of NGVs. (Exhibit B-1, p. 55) The life of the vehicles in the projects which FortisBC is targeting ranges from five to ten years. (Exhibit B-1, p. 12)

7.0 ALIGNMENT WITH ENERGY POLICY

In reviewing an expenditure schedule for acceptance under section 44.2 of the *Utilities Commission Act*, (pursuant to which the expenditures on the fuelling station for Waste Management were filed, and others may be filed) the Commission is required to consider the applicable of British Columbia's energy objectives. In its Final Submission, FEI explains how its investments further these objectives.

FEI also asserts that the policy objectives introduced in "The BC Energy Plan A Vision for Clean Energy Leadership" (the 2007 BC Energy Plan) place a new focus on NGVs. (FEI Final Submissions, pp. 19-22)

FEI submits that any future cost-effective investment in fuelling stations for "return to base" fleet customers can similarly be expected to support British Columbia's energy objectives. FEI submits that "British Columbia's energy objectives apply to CPCN applications under section 45 of the *UCA* and applications brought under 44.2 (among other sections) which both relate to utility capital investments" and that this is "explicit recognition that Government intends public utilities to be investing in cost-effective initiatives and facilities that advance the legislated objectives." (FEI Final Submissions, p. 20)

FEI states that "On November 25, 2008 GHG interim targets were set by Ministerial Order as follows:

- 2012 – six per cent below 2007; and
- 2016 – eighteen per cent below 2007 levels"

and that reductions of at least 33% are required for the year 2020 and subsequent years. (Exhibit B-1, p. 38) These targets are reflected in Section 2(g) of the *Clean Energy Act*.

Given a 2007 estimated level of GHG emissions of 67.3 million tonnes (BC Provincial GHG Inventory Report, 2007; Exhibit B-1, p. 41), this amounts to required reductions of approximately 4 million, 12 million and 22 million tonnes in 2012, 2016 and 2020, respectively. FEI maintains that fuel switching for return to base fleets will help contribute to this required reduction. To this end, FEI estimates that if its "Reference Case," (which forecasts consumption of approximately 30 PJs (or 30 million GJs) of natural gas by trucks, buses and marine vessels which have switched away from conventional fuels to natural gas by 2030) comes to pass, there will be a reduction of 865,000 tonnes of GHGs emitted in the year 2030. However, much lower reductions are forecast for earlier years in the range of approximately 25,000, 70,000 and 180,000 tonnes for the years 2012, 2016 and 2020, respectively. (Exhibit B-1, Appendix A1, pp. 19, 27)

Commission Panel Discussion

As noted by FEI, the 2007 Energy Plan indicates that the single largest source of GHG emissions in B.C. is the transportation sector. This sector accounts for 39% of GHG emissions, as compared to 11% for the residential and commercial sector. FEI "believes that reducing GHG emissions in the transportation sector is necessary in order to realistically achieve the provincial government's stated objectives." (Exhibit B-1, pp. 41-42 citing 2007BC Energy Plan) FEI submits that the use of NGVs in BC will achieve large reductions in overall GHG emissions and this will help meet the Provincial government's GHG reduction targets.

FEI notes the comment in the 2007 Energy Plan that "natural gas burns cleaner than either gasoline or propane, resulting in less air pollution" in support of its proposition that "government policy generally places a new focus on NGVs". (FEI Final Submissions, p. 19) However, the Energy Plan also describes other transportation technologies, some considerably cleaner than natural gas and in fact went on to state in the next sentence that "[f]uel cell vehicles are propelled by electric motors powered by fuel cells, devices that produce electricity from hydrogen without combustion". It continued: "[c]ars that run on blends of renewable biofuels like ethanol and biodiesel emit lower levels of greenhouse gases and air pollutants. Electricity can provide an alternative to gasoline vehicles when used in hybrids and electric cars." (2007 BC Energy Plan, p. 19)

Further, the "policy actions" for addressing greenhouse gas emissions from transportation and increasing innovation as set out in the 2007 BC Energy Plan contemplated measures such as: the implementation of a 5% renewable fuel standard for diesel, support for the federal action of increasing the ethanol content in gasoline, and development of a leading hydrogen economy with a new, harmonized regulatory framework for hydrogen. (2007 BC Energy Plan, p. 20)

As well, the "key initiatives and recent announcements" in the 2007 BC Energy Plan in this area contemplated the promotion of hybrid vehicles through tax incentives and government purchases of hybrid vehicles exclusively. The 2007 BC Energy Plan also noted the Province's intention to reduce "diesel emissions through new financial incentives to help municipalities shift to hybrid vehicle fleets and retrofit diesel vehicles with cleaner technologies." (2007 BC Energy Plan, p. 21)

The Panel is of the view that the interest expressed in electricity and hydrogen as alternative fuels for the transportation sector in the 2007 BC Energy Plan introduces an additional element of risk to FEI's proposed NGV program, particularly as these alternative fuels tend to have a lower carbon footprint than natural gas and, when viewed in comparison, would align more closely with British Columbia's energy objectives.

In its closing submission, the BCSEA states that "...the evidence establishes that substituting CNG or LNG powered vehicles for diesel powered vehicles will significantly reduce GHG emissions in BC." (BCSEA Final Submission, p. 5) CEC submits that FEI has established that NGV applications for the target markets, switching from diesel to natural gas, would result in a reduced carbon footprint, and that FEI has also established that this is consistent with the BC energy objectives. (CEC Final Submission, p. 6) The BCOAPO is silent on the alignment of the NGV program with the Provincial Government's energy policy and its impact on GHG emissions.

The Panel accepts that fuel switching from diesel to natural gas will assist the province in meeting its energy objectives. However, we note that whether this contribution is considered "significant" is largely subjective.

While subsection 44.2 (5)(a) does indeed require the Commission to consider "the applicable of British Columbia's energy objectives," subsection 5(e) requires the Commission to consider the "interests of persons in British Columbia who receive or may receive service from the public utility."

The 2007 BC Energy Plan basically contemplates government initiatives and spending but otherwise provides little guidance on who should bear any specific costs associated with programs to reduce emissions.

There is a potential for some future guidance to be provided under the *Clean Energy Act*. Subsection 18(1) of that Act defines a "prescribed undertaking" as "a project, program, contract or expenditure that is in a class of projects, programs, contracts or expenditures prescribed for the purpose of reducing greenhouse gas emissions in British Columbia." Subsection 18(2) requires the Commission to set rates for a public utility that is carrying out a "prescribed undertaking" "that allow the public utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking".
By subsection 35(n), the Lieutenant Governor in Council may make regulations... "(n) for the purposes of the definition of "prescribed undertaking" in section 18, prescribing classes of projects, programs, contracts or expenditures that encourage

(i)the use of
(A) electricity, or
(B) energy directly from a clean or renewable resource

instead of the use of other energy sources that produce higher greenhouse gas emissions, or

(ii) the use of natural gas, hydrogen or electricity in vehicles, and the construction and operation of infrastructure for natural gas or hydrogen fueling or electricity charging."

However, the Panel has not been referred to and is otherwise unaware of any regulations having been made to this point in time relating to "prescribed undertakings."

Accordingly, the Panel will examine the interests of FEI's existing ratepayers in considering the acceptability of NGV related expenditures under subsection 44.2(5).

As noted above, subsection 44.2(5)(e) requires the Commission to consider "the interests of persons in British Columbia who receive or may receive service from the public utility."

The Panel is of the view that not every expenditure that helps to meet an objective of the Energy Plan will necessarily be automatically eligible for acceptance under Section 44.2. Additional analysis is required to ensure that the expenditure is a reasonable use of limited funds and that better uses are not readily available. It is also important that proposed expenditures do not create too great of a burden on those who will be asked to foot the bill.

Further, in the Panel's view, it is important that, where there are different rate schedules in effect, the customer which benefits from the expenditure is responsible to "pay the freight". In this case, FEI's proposed NGV program targets a reduction in the GHG emissions of the transportation sector. Although many costs are borne directly by the NGV customers under the proposed Cost of Service model, cost overruns and unaccounted for costs are proposed to be borne by FEI's existing ratepayers. In addition, as discussed elsewhere in this decision, these existing ratepayers are proposed to shoulder the risk for what could amount to considerable additional costs should market conditions deteriorate, as they did in FEI's previous NGV venture.

The Panel questions whether it is in the interests of FEI's existing ratepayers to bear the costs or risks associated with reducing carbon emissions for the transportation sector when FEI ratepayers represent only a portion of the province's population and, generally speaking, are not directly responsible for those emissions. We are of the opinion that they should not. In our view, it is more appropriate that these costs be borne either by the owners of the vehicles, as they are the emitters, or by the people of the province as a whole, as they are the beneficiaries. Thus, in the Panel's view, expenditures undertaken to provide and operate infrastructure for fuelling NGVs are not sufficiently in the interests of FEI's existing ratepayers to satisfy the requirements of subsection 44.2(5)(e) as it relates to the interests of persons who take service from the public utility. The expenditures would, however, appear to be in the interests of those potential new customers who may receive CNG/LNG service from the utility.

Thus, the Panel agrees with FEI's approach that the ratepayers be "kept whole," and throughout this decision, we discuss the reasons for our agreement. **Consistent with this approach, the Panel finds that while the benefits of GHG emission reduction provides a justification for FEI's proposed NGV program, FEI's ratepayers must be insulated, to the greatest extent possible, from the costs and risks of the program.**

8.0 ISSUES ARISING

8.1 Introduction

In the view of the Commission Panel the Application raises several key issues. The first relates to the protection of the public interest in circumstances such as these, where a regulated utility is seeking to offer services which would otherwise not be subject to regulation.

Other issues which flow from the first include:

- Management of Risk
- Potential for Rate Discrimination
- Interpretation of Just and Reasonable Rates
- The Need for Confidentiality
- Adequacy of the Cost of Service Model and related Allocations

These issues all converge in the overarching concern of the Panel expressed throughout these Reasons, which is how best to insulate the existing ratepayer from various costs and risks and how to ensure that the costs and risks are actually borne by the parties who stand to benefit the most.

8.2 Regulated vs. Non-Regulated and the Public Interest

FEI has chosen to apply to the Commission to provide the new CNG and LNG fuelling services in its capacity as a regulated public utility. Given the definition of "petroleum industry" as including "the retail distribution of liquefied or compressed natural gas" and "public utility" as not including "a person not otherwise a public utility who is engaged in the petroleum industry..." in section 1 of the *Utilities Commission Act*, it is only because FEI is already "otherwise a public utility" that this new business is required to be regulated. FEI would be free to pursue this business through a non-regulated subsidiary and thereby avoid Commission oversight. Other companies, not otherwise public utilities, may enter the industry and will not be subject to regulation. In fact, FEI maintains that its CNG and LNG business models do not preclude a third party from offering the same services and that it supports other third party investment. (Exhibit B-1, pp. 16, 18) FEI states, however, that for its part, it "is interested in owning and operating NGV fuelling stations only through its regulated utility subsidiaries...in the manner proposed" in the Application. (Exhibit B-6, BCUC IR 2.29.1)

FEI also takes the position that once the Commission has approved a tariff offering for CNG and LNG service, such service becomes subject to the statutory framework relating to a utility's legal obligation to provide its service to the public, as set out in sections 28 to 30 of the *Act*. (Exhibit B-9, CEC IR 2.1.3)

Commission Panel Discussion

The Commission Panel acknowledges that the *Utilities Commission Act* does not prohibit FEI from providing CNG/LNG service offerings but that, unlike other potential market participants, if it does so, it will be subject to regulation. FEI is subject to regulation because it is otherwise a monopoly, and the regulatory framework exists to protect the public from monopolistic behaviour and the potential associated problems. (Atco Gas

Pipelines Ltd. v. Alberta (Energy Utilities Board), [2006] 1 S.C.R. 140, 2006, SCC4, para. 3) The Panel is of the view that in a case such as this one, the public interest requires that, if FEI is to provide CNG/LNG services in its capacity as a public utility, it must do so without utilizing any potential economic leverage which it may have as a result of its status as a monopoly distributor of natural gas.

The Commission Panel does not agree with FEI's position the "once Commission approval has been obtained for a tariff offering for CNG and LNG service" it will be under an obligation to provide this service to the public pursuant to section 28 of the *Act*. (Exhibit B-9, CEC IR 2.1.3) The Commission Panel is of the view that the obligation to serve stems from the nature of a monopoly provider of services with infrastructure which has natural monopoly characteristics such that a competitive market structure does not make economic sense. In the circumstances of this Application, the fuel dispensing service has no natural monopoly characteristics and could potentially be supplied by any number of competitors. As such, there is no corresponding requirement to recognize an obligation to serve such potential customers.

8.3 Risks

8.3.1 Parallels to Previous Natural Gas Program

As discussed earlier, FEI has, through a predecessor company, previously tried to establish a market for NGVs in British Columbia. However, the venture was ultimately not successful. The Panel will now examine the ways in which the current proposal is similar, and in what ways it differs, from the previous venture.

It is FEI's position that the current program has little in common with previous NGV initiatives. As previously described, this Application is based on a business model that targets return to base fleets of buses, heavy duty and vocational trucks. FEI submits that this "anchor tenant" model, although directed at a smaller target market, is less risky.

However, the Panel notes that FEI also owned and operated an NGV compression and dispensing facility for BC Transit. This facility was also constructed to serve a return-to-base fleet of heavy duty vehicles and was backed by a take or pay contract as is proposed here. FEI summarizes the main difference between the BC Transit case and the Waste Management case: "the BC Transit facility was a fast-fill design utilizing early CNG equipment technology, whereas the WM facility is time-fill facility using off the shelf proven CNG refuelling equipment." (Exhibit B-4, BCUC IR 1.11.1; 1.11.2)

One factor cited by FEI in the deterioration of the market for its previous NGV offering is an erosion of the cost differential between natural gas commodity prices and the price of conventional fuels, but that since 2000, the price differential has been re-established. FEI states that natural gas has historically had an advantage in price over other motor vehicle fuels and the lower operating cost savings result in savings for customers in spite of the higher cost of OEM NGVs or after-market conversions. Figure 3-1 in the Application outlines a historical comparison of the cost of CNG (including a $5/GJ compression charge and applicable rate riders) and diesel fuel. The figure shows that the CNG bundled rate over the ten year period commencing in 2000 would compare favourably with diesel over the entire period. Similar results are outlined in Figure 3-2 which depicts a comparison with gasoline. FEI further notes that as of the date of the Application, the advantage over diesel would be $.40/litre or 40 percent and submits that forward market prices indicate that natural gas is likely to maintain this price advantage for the foreseeable future. (Exhibit B-1, pp. 28-31)

Commission Panel Discussion

The Commission Panel acknowledges that the basis for this program and its operating fundamentals may be somewhat different from FEI's previous offering, but remains concerned that some of the factors which contributed to the lack of success with the initial NGV program remain at play with the current Application. For example, in the BC Transit case, the model was similar and the venture was not successful. As a result, the risk of stranded assets exists and with it the potential for additional costs, which FEI seeks to recover from its ratepayers.

As noted by FEI in the Application, the price of natural gas in 1992 was very favourable but this advantage eroded significantly by the early 2000's when "the price advantage of natural gas versus conventional fuels narrowed to the point where there was insufficient economic incentive to switch fuels given the differential in capital cost between the two options". (Exhibit B-1, p. 9) The Panel notes that the current price advantage related to natural gas has been affected by the current market surplus resulting from the exploitation of shale gas throughout North America. Whether this price advantage continues to be maintained over the next five to ten years remains an issue given potential for worldwide demand for LNG leading to the export of surplus natural gas in a liquefied state. We remain concerned that when initial service agreements, which FEI estimates to be 5 to 10 years (in line with the life of the vehicles), expire, the attractiveness of the programs may have diminished and customers may choose to pursue other alternatives. (Exhibit B-1, p. 12)

The Commission Panel is of the view that the primary reason this type of program will be attractive to prospective customers is because it offers a cost effective option to more traditional fuel alternatives. The current cost advantage enjoyed by CNG/LNG, is significant as FEI has pointed out. As a result, customers who choose to move forward with this program stand a very good chance of enjoying operating cost savings while also projecting a "greener" image due to the reduced emissions associated with NGVs. Of concern to the Commission Panel, as noted above, is the lack of certainty that the current price advantage of CNG/LNG versus conventional fuels will continue into the future. Additionally, the Panel is concerned about the potential for technology advancements which may provide a greener or more cost effective solution than that offered by CNG/LNG. For example, there may be increasing support for electric vehicles that are fuelled by energy generated from renewable hydro. In this regard, the Panel notes that the introduction of hybrid electric vehicles was cited by FEI as a factor in the decline of the NGV market in BC in the past ten years. (Exhibit B-1, p. 10)

8.3.2 Potential for Stranded Assets

For the purposes of the discussion in these Reasons, the Commission Panel considers a stranded asset to be an asset with a book value that exceeds its market value, in circumstances where the asset is no longer used or useful for utility purposes. The potential for stranded assets in the business model presented by FEI in this Application in particular, arises because of the differences in the time period covered by fleet operator service agreements (which FEI proposes to match to the life of the vehicle) and the asset life of the station infrastructure (which is estimated to be 20 years). As FEI has acknowledged, the risk associated with the expiry of the service agreement before recovery of the full capital cost of the station is one of under-recovery. Where a customer does not choose to use natural gas as its fuel beyond the initial term of a service agreement, 10 to 15 years of unrecovered costs could remain. Based on the average station infrastructure cost of $700,000 utilized in Figure 2-1 of the Application, this would amount to a potential for stranded asset costs ranging from $350,000 to $525,000 for each project depending on the period covered in the initial service agreement. (Exhibit B-1, pp. 12-13, 65)

FEI states that this recovery risk can be mitigated in a number of ways:

- Stations could be relocated to another project location resulting in an estimated recovery of 50 to 70 percent of the capital;
- Station assets could be sold into other jurisdictions [No cost mitigation estimates were provided for this instance]; and/or
- FEI could seek to negotiate contractual terms with customers to mitigate risk.

With respect to the last measure, the Waste Management Agreement contains a clause which stipulates that the customer must pay for any unrecovered amount if it chooses not to renew the Agreement (Exhibit B-1, Appendix D-1).

None of the Interveners expressed significant concern with respect to the risk of stranded assets. In reference to the Waste Management Agreement, BCSEA states that existing customers are provided significant protection against stranded asset risks with the 'take or pay' feature, bolstered by protection against unrecovered capital where a contract is not renewed. Additionally, it notes that the protection is greater than that provided by the Mains Extension test, which is applied in instances where there are customer driven extensions of the existing pipeline. (BCSEA Final Submission, p. 7) BCSEA makes no further comment with regard to stranded assets in its comments on the proposed General Terms and Conditions. BCOAPO notes that in its view the "risks of stranding assets are low" and the tolling proposal will provide "for fairly certain cost recovery." (BCOAPO Final Submission, p. 1) The CEC argues that the 'take or pay contracts', FEI's expectation that 50 to 70 percent of remaining capital costs can be recovered, and the potential for FEI to negotiate renewal or buyout terms provides a risk mitigation which significantly exceeds that available for other customer classes. The CEC concludes its comments on this issue by stating "the risks of stranded assets due to customers switching to other fuel sources exists across the FEI system and the risk for the proposed NGV assets is relatively low in comparison." (CEC Final Submission, pp. 3-4)

Commission Panel Determination

As noted earlier, the Panel remains concerned that there is a risk for stranded assets due to the potential for changing circumstances with respect to the use of natural gas as a transportation fuel. Further, the Panel is not convinced that FEI has made sufficient provisions within the proposed General Terms and Conditions to ensure the potential for stranded assets is adequately mitigated. We note that the 'take or pay' provision within the General Terms and Conditions ensures that the forecast cost of service over the term of the service agreement will be recovered. However, this provides no relief in the event that a customer decides not to renew after the initial 5 or 10 year term. FEI has stated that there are opportunities for it to recover 50 to 70 percent of the remaining unamortized capital in such instances. While the Panel will not dispute that the assets may still have useful life remaining, we do question whether the value would be realized in such instances. In the Panel's view the biggest threat to customer renewal is changing circumstances which may make CNG/LNG less attractive as a fuel source. This may be because of a change in the economics or through the introduction of new technology over the 5 or 10 year initial term period. In such instances the migration away from this solution would not likely be made by one customer but more likely by many and would apply to new customers as well. Thus, if such a change were to occur as it did with the previous NGV offering, it would be unreasonable to assume that reselling or relocating the assets would be certain or even likely. If resale or relocation did not occur, the cost proposed to be borne by existing ratepayers, as noted previously, would range between $350,000 and $525,000 per non renewing customer, based on average infrastructure costs of approximately $700,000.

As also noted earlier, in the case of the Waste Management Agreement, the 'take or pay' feature is bolstered by protection against unrecovered capital costs through a provision requiring Waste Management to purchase the fuelling station at its remaining undepreciated capital cost, if the contract is not renewed. However, FEI did not include such a provision in its proposed General Terms and Conditions, but stated that it can "... negotiate contractual terms that mitigate risk." (Exhibit B-1, p. 65) The Panel is of the view that, in the circumstances of this Application, a period of 5 to 10 years is a long time and, as evidenced by occurrences over the last few years, a great deal of change can occur over even a relatively short period of time. Failure to include provisions to protect against the risk of stranded assets would not be in the public interest. **Accordingly, the Commission Panel has determined that to be approved, the General Terms and Conditions must include a provision requiring the customer to pay any unrecovered capital in those cases where the initial contract is not renewed, or a similar provision that provides equivalent protection.** The Panel understands adding this provision may result in some potential customers being lost because they are not prepared to bear that risk. However, we also see no reason why the ratepayer should be required to do so either.

8.3.3 "Kick Starting" the Market

FEI submits that it should build the fuelling facilities to "kick-start" the market and that it is uniquely qualified to do so. FEI argues that the market for CNG in BC has stagnated in the past ten years or so, and that it must provide CNG/LNG service as a regulated entity to revitalize the market. It also states that it "is not aware of other businesses with the expertise and technical capability that have committed to developing the B.C. fuelling station market." (FEI Final Submissions, pp. 23-24)

Commission Panel Determination

In the Panel's view, while the lack of an experienced and committed CNG supplier may indeed be a reason for the decline in CNG use, FEI has provided a number of other factors, including an insufficient price spread between natural gas and conventional fuels, the introduction of hybrid electric vehicles and, significantly, the cost of engine conversion and the discontinuation of federal government incentive grants to support these conversions. (Exhibit B-1, p. 47, Appendix A-2, pp. 10-11) These last two reasons are underscored by the fact that FEI provided incentive funding to Waste Management to cover the entire incremental cost of purchasing 20 CNG fuelled vehicles over 20 diesel fuelled vehicles. The incentive funding was provided under the terms of a separate Contribution Agreement. (Exhibit B-1, p. 47; Exhibit B-8, BCSEA IR 2.27.2) FEI states that it "believes that incentive funding is important to achieving near-term opportunities...". (Exhibit B-1, Appendix A-1, p. 29) In fact, all three of FEI's demand scenarios assume the availability of incentive funding. FEI states that "if no incentive funding is available through government or other sources, NGV adoption under all three scenarios will be insignificant over the short and long term." (Exhibit B-11, BCUC IR 3.7.2)

Thus, the Panel notes the potential role of incentive funding in 'kick-starting' the market and is concerned that FEI has not established the potential existence of any market in the absence of such incentive funding. The Panel further notes that If it were the case that the market is dependent on incentive funding, from one source or another, then it introduces an additional element of risk into this service offering, in that incentive funding may not be sufficient or even available in the longer term.

Accordingly, while FEI may – or may not - be able to kick start the market, the Panel finds the evidence supporting FEI's assertion that it is uniquely qualified to do so is less than compelling. The Panel finds that there is a significant potential for risk in assuming the long term viability of this potential market and directs that ratepayers be insulated from this risk to the fullest extent possible.

8.4 Implications of Sections 59-62

8.4.1 Rate Discrimination

Section 59(2)(b) of the *UCA* states: *A public utility must not 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.* However, FEI argues that it needs considerable flexibility to negotiate terms of individual agreements that could extend beyond the proposed General Terms and Conditions. The Panel is concerned that this potential for significant variations in the terms of each custom service agreement could constitute a discriminatory extension of a privilege to a customer. For example, FEI states that the initial term of future contracts will vary. (Exhibit B-6, BCUC IR 2.3.1) FEI further admits that there will still be un-recovered costs at the end of the term unless the term is as long as the life of the underlying assets and that, in most cases, customers will expect a term only as long as the expected life of their vehicle assets. (Exhibit B-7, BCOAPO IR 2.1.1) In the case of Waste Management, FEI was able to negotiate a provision to ensure recovery of the undepreciated cost of the asset at the end of the initial contract term. If another customer did not agree to such a provision, the Panel questions whether both parties would have, in fact, been extended the same rule or privilege.

Commission Panel Determination

Given the General Terms and Conditions proposed and the negotiation process as described by FEI, there is a potential for a benefit or benefits being made available to one LNG/CNG customer but not another. **Therefore, the Panel finds that FEI's proposal, which provides for the potential to negotiate significant variations among different service agreements, is not acceptable.** The Panel favours a more structured approach to the General Terms and Conditions, which will result in a more standard form, leaving less to negotiate and consequently reducing the likelihood that an agreement will be discriminatory within the meaning of section 59(2)(b) of the *Act*.

8.4.2 Just, Reasonable and Fair Rates

Both the Waste Management Agreement and the proposed General Terms and Conditions are subject to approval under sections 59-61 of the *UCA*, which require that rates be not unjust or unreasonable or unduly discriminatory. Subsection 59(5) of the *Act* defines an unreasonable rate as one that is more than a fair and reasonable charge for service of the nature and quality provided by the utility, or is insufficient to yield a fair and reasonable compensation for the service provided by the utility. The Panel is concerned that the cost of service model as reflected in the proposed terms and conditions may not recover the full, actual cost of the services provided.

BCSEA argues that the Waste Management Agreement rate is just and reasonable because it is based on the cost of service and it is satisfied that there is no cross-subsidization by ratepayers. (BCSEA Final Submission, pp. 7-8) While the Panel agrees that a rate that is based on the cost of service could be just and reasonable, we are concerned that the General Terms and Conditions, as proposed by FEI, base the cost of service on forecast, as opposed such costs. (Exhibit B-6, BCUC IR 2.1.1) Actual costs may differ from forecast costs due to elements as cost overruns during construction. Further, higher inflation rates or taxes than originally anticipated, and potential increases to the utility's allowed rate of return will not be recovered from the customer. In addition, as discussed above, depending upon the term of the contract with the LNG /CNG customer, the cost of service as proposed by FEI, may not recover all of the potential costs to FEI of providing the service. The proposed cost of service model also does not include any costs relating to marketing of the program. While some of these costs may not be significant, there is a potential, under certain market scenarios, for some to be consequential. Thus, the Panel is concerned that there is a potential for cross-subsidization by ratepayers.

Commission Panel Determination

CEC argues that it is just and reasonable to recover only forecast costs and that the Mains Extension test supports this approach. (CEC Final Submission, p. 8) However, the Panel questions this comparison. In Exhibit B-9, CEC IR 2.8.1 FEI asserts that existing customers share in the costs of extending the system for a Mains Extension <u>because</u> they see benefit from additional load (emphasis added). The Panel does not agree with this characterization and does not consider Mains Extensions to be an appropriate basis of comparison. While additional load and the resulting potential for lower delivery rates may indeed be a benefit of a Mains Extension to existing ratepayers, it is not the reason for the cost sharing. The purpose of a Mains Extension is to connect new customers to the system, thereby extending the distribution system. A Mains Extension within the service area of a regulated utility can only be undertaken by that utility. Generally speaking all ratepayers – including the new ratepayers who will receive the service – will be required to share in the costs of the extension, as they share in all of the costs related to the operation of the distribution system. In cases where the connection costs are excessive, a utility may recover some of the costs from the new ratepayers through a "contribution in aid of construction." It is appropriate to share costs in this fashion since all ratepayers get connected to the utility at one time or another, so all receive the same benefit.

A CNG or LNG refuelling facility is not an extension of the distribution system. Most existing ratepayers do not require a return to base CNG or LNG refuelling facility. With the cost of service model, CNG /LNG customers do not share in all the costs of the distribution system beyond those recovered under the applicable Rate Schedule, but only in the incremental cost of providing their CNG /LNG service. Further, as noted earlier, the construction and operation of CNG /LNG fuelling facilities are not required to be regulated, unless they are provided by a [regulated] public utility. If a CNG station, for example, were provided by an unregulated entity, there would be no requirement, or need, for existing ratepayers to share the cost of providing the facilities, yet they would still benefit from increased throughput in FEI's distribution system. The Panel does not agree that existing ratepayers should share the costs just because FEI is providing the fuelling facilities.

The Panel finds that FEI has failed to provide a convincing argument that it is just and reasonable that existing ratepayers should subsidize the costs of the refuelling facilities. We believe that there should be as little potential for cross-subsidization as it is possible to achieve. In its submission, FEI endorses this approach when it describes its cost of service model: "At a high level, it captures all of the costs associated with providing service to an NGV customer, and uses these costs to generate a rate that recovers the cost of service from the NGV customer over the term of the service agreement. The intent is to keep other natural gas customers whole." (Exhibit B-1, p. 11) However, as discussed, the Panel is concerned about the effect of unbudgeted costs, cost overruns and other factors that could require ratepayer subsidization. The Panel therefore requires that, to the extent possible, none of the actual costs of the CNG/LNG service offerings be recovered from existing ratepayers. Any General Terms and Conditions must therefore include additional assurance that the total actual cost of the refuelling facility will be recovered from the CNG/LNG customer to the extent possible.

8.5 Confidentiality

In Order G-6-11 dated January 14, 2011 the Commission Panel approved the Waste Management Agreement as a Tariff Supplement on an interim basis and subject to certain conditions, including the condition that if the Waste Management Agreement was to be amended in accordance with the Commission's determinations and refiled, the Agreement was to be refiled on a non-confidential basis.

On February 25, 2011 FEI refiled the amended and restated Waste Management Agreement as Tariff Supplement J-1 on a non-confidential basis.

In its Reasons for Decision in support of the January 14, 2011 Order (Order G-6-11) the Commission Panel noted that section 62 of the *Act,* requires that: "A public utility must keep a copy of the schedules filed open to and available for public inspection under commission rules." The Panel noted at that time that: "...because transparency is a fundamental principle of sound regulation, the Commission requires public utilities to publically file all approved rates, rate schedules and tariff supplements unless there are very unusual circumstances."

In its Reply Submission (at p. 2) FEI endorses the rationale behind the Commission's decision that the public interest will generally favour the publication of rate schedules, but notes the support received from the CEC on the issue of confidentiality .

CEC submits that individual customer information does not need to be made public in the oversight process. It submits that important regulatory information could be separated from individual information and that adequate aggregate information with ranges could be made available. CEC submits that "disclosure of individual contract provisions may not be necessary or even sensible in order to protect FEI's commercial ability to negotiate terms." (CEC Submission, p. 12)

BCSEA notes that "both public access to public utilities' rate schedules and the protection of legitimate claims of confidentiality are important, and potentially conflicting interests." (BCSEA Submission, p. 9)

Commission Panel Determination

The Commission Panel remains of the view that there is no compelling reason why new customer-specific rate schedules should not be in the public domain, especially if each contract is designed to recover costs in a just and fair manner. The Panel does not support the need for confidentiality to allow FEI to negotiate different commercial terms with different customers, as suggested by the CEC.

Exhibit A2-9 is an example of a Tariff Supplement which relates to a particular individual customer. The Commission Panel believes that rate schedules should continue to be public documents to ensure openness and transparency and the absence of any form of discrimination in rates. However, the Panel acknowledges the possible need to protect commercially sensitive information in certain exceptional cases and notes that FEI has the ability to apply to the Commission in the event there are extenuating circumstances which may relate to a particular customer.

8.6 Cost of Service Calculation

The Commission Panel agrees with FEI that public interest considerations support the inclusion of terms and conditions which ensure the cost of the facilities will be recovered from the customer. This is critical to the Panel's review, consideration and potential approval of any General Terms and Conditions for future contracts.

8.6.1 Capital Cost Recovery

As noted in Section 5.1.3 of this decision, FEI proposes to use the forecast capital cost of the fuelling station as an input to the Cost of Service Model, including the "take or pay" provision. In its proposed model, any overruns would be recovered from existing ratepayers, absent a finding of imprudence. (Exhibit B-6, BCUC IR 2.1.9; 2.1.10)

FEI argues that customers want CNG and LNG rates that are known with certainty at the time a contract is entered and that this will necessarily precede the construction of the facility. (Exhibit B-6, IR BCUC 2.1.8) FEI further states that "the forecast cost of service is likely to be reasonably accurate," and the "bulk of the rate [being] composed of [capital and O&M] costs that can be estimated with a relatively high degree of certainty." (Exhibit B-6, BCUC IR. 2.1.1, 2.1.11)

Commission Panel Discussion

Given that FEI proposes to recover any cost overruns from general ratepayers, as noted above, the Panel is concerned with the use of forecast, as opposed to actual capital costs. For example, when the refuelling station for BC Transit was constructed in 1991, the actual cost exceeded the forecast cost by a factor of 75%. (Exhibit B-6, BCUC 2.1.6) In the case of Waste Management, actual construction costs exceeded forecast by approximately $37,000, a factor of 5%. (Exhibit B-11, BCUC IR 3.1.2)

In the Panel's view, the importance of using actual as opposed to forecast capital costs is further underlined by the fact that, at least for LNG, FEI has, at a high level, estimated the operating costs of the fuelling station based on the forecast capital cost. To the extent that the forecast capital cost is incorrect, this divergence will be magnified as the basis for the calculation of estimated operating costs will also be inaccurate. (Exhibit B-6, BCUC IR 2.10.2)

The provision of a fuelling station at a customer's premises is not, in the Panel's view, a typical utility project. Rather, such a project is essentially a custom construction project for an individual customer. In this regard, the Panel notes that FEI also contracted to provide other "associated" construction work to Waste Management under a separate agreement on a cost plus basis with an estimated margin of approximately $115,000. (Exhibit B-3, BCUC Confidential IR 1.9.1; Exhibit B-11, BCUC IR 3.1.4)

Accordingly, the Panel directs that FEI and use the actual construction costs in the calculation of the cost of service in any revised General Terms and Conditions. This could mean that the determination of the rate perhaps cannot be finalized until after construction is completed. Alternatively, hiring a third party construction company to provide the service on a fixed price basis would serve to provide the customer with certainty for the cost at the outset. In any event, as FEI has noted, since the forecast cost is assumed to be reasonably accurate, in the Panel's view the use of actual costs should not introduce an unacceptable level of uncertainty at the time the contact is being negotiated.

8.6.2 Operating and Maintenance Costs

Operating and maintenance cost forecasts for CNG are based on estimates of the material and labour costs associated with maintaining the fuelling station, and any additional administrative expenses associated with the service agreement. (Exhibit B-1, p. 56) In the case of LNG, FEI provided a high level estimate for O&M costs equivalent to 2% of the capital cost of the fuelling system. However, FEI now states that subsequent discussions with the manufacturer suggest that a range of 3%-6% is likely to be more reasonable. (Exhibit B-6, BCUC IR 2.10.2) The Panel notes that the amount for O&M that will be charged to the CNG/LNG customer is actually lower, as FEI proposes to take 14% of gross O&M to include in "capitalized overhead," to be recovered over a 37 year period. Once again, FEI proposes that any underestimate be recovered from all non-bypass customers. (Exhibit B-4, BCUC IR 1.9.6)

Commission Panel Determination

The Panel is concerned that FEI is proposing to recover estimated operating and maintenance expenses as opposed to actual. While FEI will gain experience as the program progresses, the risk of cost overruns remains, particularly in the early stages of the program, and particularly in the case of LNG, where there is less experience to draw upon. Ideally, FEI would charge its NGV customers the actual operating and maintenance costs incurred. **The Panel directs FEI to consider modifications to the General Terms and Conditions that will ensure that the operating and maintenance costs recovered from the customer are as close as possible to the actual operating and maintenance costs incurred.**

The Panel discusses the issue of capitalized overhead further in Section 8.6.4 below.

8.6.3 Escalation Factor

FEI proposes that that a 2% per annum escalation factor be applied to inflate O&M costs during the contract term. (Exhibit B-1, p. 57) The Panel notes that, in the case of the Waste Management Agreement, this escalation factor was only applicable to the first ten year term of the contract, and not to subsequent terms.

Commission Panel Determination

The Panel is concerned that, over the time periods contemplated in the Application, this escalation factor could become unrealistic. **FEI is therefore directed to include an escalation factor equal to the value of the British Columbia Consumer Price Index for all items, as produced by BC Stats on a monthly basis in any revised General Terms and Conditions.**

8.6.4 Depreciation and Amortization Expense

FEI proposes to depreciate the capital assets making up the fuelling station over either 10 or 20 years, which is consistent with the expected life of a fuelling station, being 20 years, with the exception of "capitalized overhead," which it proposes to depreciate in accordance with its average rates, or 2.7%. However the use of 2.7% will mean that the depreciation period will exceed the contract term such that this amount will not be fully recovered from the customer (absent an extension of the contract by the customer beyond the useful life of the other assets) putting other ratepayers potentially at risk for unrecovered costs. In the case of the Waste Management Agreement, FEI acknowledges that "the total present value of the free cash flow is negative because the depreciation period of the capitalized overhead is longer than the 20 year period.

That is, the full recovery of the capitalized overhead does not occur within the 20 year period." (Exhibit B-4, BCUC 1.24.1)

FEI has also excluded any provision for negative salvage value from its depreciation rate calculation and proposes to apply any removal costs to income in the year in which they are incurred. (Exhibit B-4, BCUC IR 1.22.2) In the circumstances of the CNG/LNG service offerings, these costs, which are directly associated with the service offering to the individual customer, would fall to be borne by rate payers.

Commission Panel Determination

The Commission Panel is again concerned that this cost recovery model does not adequately recover the full cost of the service from the customer over the unique timeframe associated with these projects and therefore directs FEI to include 100% of the operating and maintenance costs in the cost of service calculation and to include zero percent of gross operating and maintenance costs as capitalized overhead for CNG/LNG projects in any revised General Terms and Conditions. The Panel further directs FEI to include the estimated net negative salvage value in the cost of service calculation in any revised General Terms and Conditions.

8.6.5 Other Costs

The Commission Panel notes that there are a number of other costs on which FEI has been silent in its cost of service model. These include overhead and marketing costs related to the NGV programs and an allowance for any increase to FEI's allowed rate of return or cost of debt. For example, FEI has a full-time salesperson assigned to its NGV program. (Exhibit B-11, BCUC IR 3.5.2)

Commission Panel and Determination

As discussed throughout these Reasons for Decision, the Commission Panel requires that to be approved, any General Terms and Conditions must include a cost of service calculation which reflects the actual full cost of service, including the cost of establishing, maintaining and promoting the program, as closely as possible. **The Commission Panel therefore directs that any revised General Terms and Conditions contain a provision whereby FEI will estimate the overhead and marketing expenses which relate to the CNG/LNG program and the expected CNG/LNG sales volume and allocate those costs in a reasonable manner among CNG/LNG customers going forward.**

8.7 Contract Term

The cost of service model generally recovers the cost of providing service to a particular customer, over the term of its individual contract. However, unless the contact term matches the useful life of the fuelling station assets (20 years), there will be an asset remaining which may or may not be useful, and for which the cost has not been recovered, and therefore has the potential for being stranded. As noted earlier, in the case of Waste Management, FEI was able to negotiate a term requiring Waste Management to purchase the fuelling station for its un-depreciated capital cost if Waste Management chose not to proceed with the second ten year tem of the Agreement. This provision serves to a large extent to protect against this risk. (Exhibit B-1, p. 65)

Commission Panel Determination

As discussed in section 8.3.2 of these Reasons, the Commission Panel is of the view that a contractual term which serves to ensure that the customer pay the full cost of the fuelling station over its twenty year life is essential to mitigating the risk of stranded assets. **Accordingly, the Panel directs FEI to include a provision similar to that employed in the Waste Management Agreement, or some other equivalent provision which will result in the customer paying the full cost of the fuelling station during the term of the contract in any revised General Terms and Conditions.**

8.8 Carbon Credits

Treatment of any potential carbon credits which may be available from the NGV service offering remains unresolved at this time. FEI confirms that there may be additional value in monetizing GHG emission reductions as offsets in the event that there is a "suitable protocol" for switching from a higher carbon fuel to a lower carbon fuel. FEI advises that current industry practice in this area would see the benefit of the GHG reductions being attributed to the end user which is reducing its carbon footprint. However, FEI believes it unlikely that it would be cost effective to undertake validating and verifying emission reductions for an individual project. FEI proposes to consider including a term that it is entitled to any GHG emission credits in its future negotiations, in the event there are multiple projects supporting third party validation and verification on an aggregate basis. (Exhibit B-1, p. 34)

Commission Panel Determination

The Panel is of the view that carbon has a value and that value should be determined and recognized. **The Panel therefore directs FEI to quantify the GHG reductions and potential for carbon credits in future applications and describe any steps that have been taken by the parties to monetize those potential benefits.**

8.9 Competition

While this new business may or may not be a natural extension of FEI's existing regulated business, as argued by FEI at page 19 of the Application, the retail distribution of liquefied or compressed natural gas has no natural monopoly characteristics. Accordingly, non-regulated entities are free to enter this marketplace. This is a significantly different situation than that faced by FEI in the regulated distribution of natural gas to consumers and businesses.

Commission Panel Discussion

Given that FEI may be in competition with other non-regulated businesses, the Commission Panel is concerned about the potential for cross subsidization by FEI's existing ratepayers. The Panel considers that the public interest would not be served by effectively providing FEI with a competitive advantage over other potential participants in the industry by allowing FEI to subsidize the costs of what would otherwise be an unregulated service, with existing ratepayer money. This again supports the Panel's determination that, to the extent possible, the full cost of CNG and LNG service is to be recovered from the CNG and LNG customers, respectively.

9.0 COMMISSION PANEL DECISION

9.1 General Terms and Conditions

The Panel is persuaded that benefits will accrue to FEI, FEI's NGV customers, its ratepayers and the people of British Columbia if the NGV market can be kick-started. FEI's NGV customers could potentially save a significant amount on their fuel costs and its ratepayers may enjoy some rate stability or even a reduction in terms of delivery charges, other things being equal, if the load building that is forecast can be realized in the longer term. In addition, residents of the province will benefit from GHG reductions if diesel and gasoline vehicles switch to natural gas as a fuel. Further, a potential exists for these GHG reductions to be monetized by FEI's NGV customers. Accordingly, the Panel finds the benefits outlined in this Application to be generally in the public interest.

However, given the history of FEI's prior unsuccessful attempt to promote CNG as a transportation fuel, based in part on the behaviour of the relative market prices for diesel and natural gas, the Commission Panel finds that existing ratepayers should bear minimum risk in the service offerings proposed in this Application. In the Panel's view, the public interest will not be protected without strong measures in place to ensure that the proposed CNG or LNG customer pays for the full associated cost of service. Elsewhere in this decision, we have discussed the General Terms and Conditions as proposed by FEI. While FEI states that it supports the concept of cost recovery, we have found that the actual proposed General Terms and Conditions do not, in fact, recover all, or a even a sufficient proportion of the costs of the CNG /LNG offerings from the customers of those offerings to make the Application, as filed, in the public interest.

Therefore, the Commission Panel rejects the General Terms and Conditions, as proposed. The Commission Panel would be prepared, however, to approve revised General Terms and Conditions which better reflect full cost recovery from the CNG/LNG customer, as outlined in the Reasons above. In particular, the Panel invites FEI to file revised General Terms and Conditions which, in addition to the "Take or Pay" commitment, require that the rates charged to customers:

- Use actual construction costs as opposed to forecast costs;
- Fully recover the capital cost of the fuelling station (including estimated negative salvage value) within the term of the contract or include provisions requiring the customer to purchase the equipment for its undepreciated capital cost;
- Ensure that actual operating and maintenance costs are recovered as fully as possible;
- Inflate operating and maintenance costs by the regional CPI annually;
- Reflect no amount for capitalized overhead such that all operating and maintenance costs are recovered from the CNG/LNG customer over the term of the contract; and
- Provide an allowance for overhead and marketing to be recovered from the CNG/LNG customer.

9.2 Future Reporting Requirements

The Commission Panel is also concerned that the twenty year time horizon for the CNG assets is a lengthy time and FEI's proposed business model is therefore subject to the considerable uncertainty inherent in predictions of market forces a long time out. **Accordingly, the Panel directs FEI to keep the costs and**

revenues associated with the Waste Management Agreement and any other offerings separate and distinct and to monitor such offerings during a two year test period and provide a report by March 31, 2013. The scope of the report should include the topics listed in Appendix 2.

9.3 Waste Management Agreement

The Waste Management Agreement, for which interim approval was granted, is a concrete example of an application of the proposed General Terms and Conditions. The contract was approved on an interim basis only, to allow for a more thorough review of the context and the issues arising.

The Waste Management Agreement includes an additional provision which is intended to ensure that Waste Management pays the cost of the new service and the capital asset necessary to provide it. However, FEI suggests that some of these provisions may not be universally acceptable to potential new customers and therefore should be open for negotiation.

For example, in addition to the "take or pay" provision which is central to the business model and which purportedly ensures recovery of the cost of service over the term of the contract, the Waste Management Agreement covers a twenty year time period, coinciding with the expected life of the fuelling station. (The Agreement comprises an initial term of ten years, and a renewal term of a further ten years with a provision requiring Waste Management to purchase the fuelling station (for roughly its undepreciated capital cost) if Waste Management elects not to proceed with the second term). This provision is not reflected in the proposed General Terms and Conditions.

There are also real potential costs which may or may not be recovered from Waste Management. For example, as discussed earlier, the actual construction costs for the Waste Management facility exceeded the forecast cost used in the cost of service calculation. As well, for example, any increases in operating costs beyond those accounted for by the escalation factor, and increases to taxes and FEI's allowed ROE will also not be captured, and therefore will not be recovered from this customer.

Commission Panel Determination

The Commission Panel approves the Waste Management Agreement, filed as Tariff Supplement J-1 on March 25, 2011, in final form. Although the Panel remains concerned with the potential for increased costs which are not recoverable from Waste Management, this contract is in effect and because it is unique, the level of risk is, for the most part, acceptable in that it is identifiable and quantifiable and can be limited to this contract only. The Panel therefore approves this Agreement on an exception basis only. The Panel addressed the risks which it has identified as unacceptable for future contacts in its consideration of the proposed General Terms and Conditions.

9.4 Expenditures on Waste Management Fuelling Station

As noted above, FEI is also seeking acceptance of its expenditures on the Waste Management fuelling station and related facilities pursuant to s. 44.2 of the *Act*. By subsection 44.2(5) the Commission is required to consider a number of items. Of relevance to this Application are:

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

(b) the most recent long term resource plan filed under s. 44.1...; and

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

British Columbia's energy objectives are set out in the *Clean Energy Act* SBC 2010 c. 22 s. 1. FEI submits that the energy objectives which apply to this Application are:

(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...;

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

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

(j) to encourage economic development and the creation and retention of jobs.

(Application, p. 45)

Commission Panel Determination

With respect to energy objective (d), in the Commission Panel's view the promotion of innovative technologies refers only to those "that support energy conservation and efficiency and the use of clean or renewable resources". The promotion of natural gas in place of diesel as a fuel, although reducing carbon emissions, does not, in the Panel's view, necessarily support energy conservation and/or energy efficiency. In terms of "energy efficiency" the Panel specifically notes that natural gas is in fact less efficient as a fuel than diesel by a factor ranging from 10% to 20 % and that in its calculations, FEI used a figure of 17% for efficiency loss. (Exhibit B-1, pp. 50-51; Exhibit B-8, BCSEA IR 2.3.1) Further, the term "clean or renewable resource" is defined in the *Clean Energy Act* and does not include natural gas. Therefore, the Panel finds that this particular objective is not applicable to the circumstances of this Application.

The Panel does accept, however, that the use of natural gas as a fuel will result in fewer carbon and other emissions than the diesel which it replaces and the Application is therefore consistent with the energy objectives which relate to the reduction of greenhouse gas emissions. FEI estimates that the Waste Management project, which involves the replacement of 20 diesel vehicles with vehicles which consume natural gas, will result in a 214 tonne reduction of greenhouse gas emissions per year. The Panel further accepts that there may be some economic development benefits in that certain component manufacturers for NGVs are located in British Columbia.

FEI submits that its 2010 Long Term Resource Plan discussed the impacts of the service offerings applied for "at a high level" but that this Application contains more detailed information. (Exhibit B-1, p. 5) The Panel agrees that the information provided in the LTRP was at an extremely high level and therefore finds that the Application is not inconsistent with FortisBC Energy's most recent Long Term Resource Plan.

FEI, as noted above, submits that the expenditures are in the interests of persons in British Columbia who receive or may receive service from it in that the Waste Management fuelling facility will add cost-effective load to its system, thereby reducing delivery costs, other things equal, for its existing ratepayers, while providing the new customers with economic benefits through reduced operating costs. FEI states that the "typical payback period for a heavy duty fleet operator switching from diesel to CNG is approximately four to six years." (Exhibit B-1, pp. 1, 29-30, 50, 63)

The Panel accepts that the addition of cost effective load may benefit existing ratepayers, *other things equal* but reiterates that, in its view, existing ratepayers are not the main beneficiaries of the expenditures necessary for this project. Further, other things may not remain equal and to the extent that the increased load creates the need for additional infrastructure, this may not be the case. As well, the benefits to new CNG/LNG customers are dependent to a large extent on the continued price differential as between natural gas and diesel. Finally, the benefits attributable to existing ratepayers from the addition of cost-effective load are not dependent upon FEI undertaking the projects, but would flow in any event if the projects were undertaken by other market participants.

FEI also submits that the expenditures are in the public interest because the cost of the facilities is to be recovered from Waste Management over the term of the Waste Management Agreement. (Exhibit B-1, p. 1) As discussed throughout these Reasons, this factor is critical. The Panel's approval of the Waste Management Agreement is predicated on the fact that, in the Panel's view, the Agreement does accomplish cost recovery from the customer to a significant extent. **The Commission Panel therefore accepts the expenditures on the Waste Management fuelling station and related facilities pursuant to section 44.2 of the *Utilities Commission Act.***

10.0 FORTISBC ENERGY CNG AND LNG SERVICES – SUMMARY OF DETERMINATIONS

1. The Waste Management Agreement, as amended and refiled on March 25, 2011 as Tariff Supplement J-1, is approved in final form.

2. The expenditures made to provide the Waste Management fuelling station and related facilities in the final amount of $775,031 are accepted pursuant to s. 44.2 of the *Act*.

3. Approval of FEI's proposed General Terms and Conditions, specifically, the addition of a new section 12B relating to CNG and LNG Service, is denied.

4. The Commission Panel will approve revised General Terms and Conditions which, in addition to the proposed "Take or Pay" commitment, better reflect full cost recovery from the potential CNG/LNG customer, as described herein;

5. Subject to FEI filing revised General Terms and Conditions acceptable to the Commission, depreciation rates are approved in accordance with the following table:

Asset	Estimated Useful Life (years)	Depreciation Rate (%)
CNG Dispensing Equipment	20	5%
LNG Dispensing Equipment	20	5%
Foundations	20	5%
Pumps	10	10%
Dehydrator	20	5%

No amounts will be approved for capitalized overhead.

The following deferral accounts are approved:

a. A non-rate base deferral account attracting AFUDC to capture the cost of the current application, including the cost of the Waste Management Application and to recover these costs from all non-by-pass customers by amortizing them through delivery rates commencing January 1, 2012 over a three year period. [Future individual application costs must be recovered from those customers.]

b. A non-rate base deferral account attracting AFUDC to capture the O&M costs and the cost of service associated with the capital additions to the delivery system incurred and the CNG and LNG Service recoveries received prior to January 1, 2012 for contracts approved by the Commission, and to recover or refund the balance to all non-bypass customers by amortizing the balance through delivery rates commencing January 1, 2012 over a three year period.

c. An ongoing rate base deferral account to capture incremental CNG and LNG recoveries received from actual volumes purchased in excess of minimum contract take or pay commitments to be refunded to all non-bypass customers by amortizing the balance through delivery rates over a one year period, commencing the following year, to be effective as of January 1, 2012 pursuant to sections 59 to 61 of the Act.

FEI Proposed General Terms and Conditions – Section 12B

12B. Vehicle Fueling Stations

12B.1 **Compression and Dispensing Service for Compressed Natural Gas (CNG) Fueling and Fuel Storage and Dispensing Service for Liquefied Natural Gas (LNG) Fueling** - Terasen Gas will make extensions to the Terasen Gas System and provide CNG and LNG Services to vehicles in accordance with the provisions of this section.

CNG or LNG Service will be provided under the terms and conditions of a Service Agreement between Terasen Gas and the Customer. The CNG and LNG Services are described below:

CNG Service will typically consist of:

- installing and maintaining a CNG fueling station, including, but not limited to, the compression, gas dryer /dehydrator, high pressure storage, dispensing equipment; and
- dispensing of compressed natural gas.

LNG Service will typically consist of:

- transport and delivery of the LNG from TGI's LNG facilities to the Customer premise by LNG tankers;
- installing and maintaining a LNG fueling station, including, but not limited to, the storage, vaporizer, pump, dispensing equipment; and
- dispensing of liquefied natural gas.

12B.2 **Ownership** - All CNG and LNG fueling stations will remain the property of Terasen Gas.

12B.3 **Cost of Service Recovery** – Customers will be charged a "take-or-pay" rate (i.e. minimum contract demand) under the Service Agreement that recovers the present value of the forecast cost of service associated with provision of CNG or LNG Service over the term of the Service Agreement, where the minimum contract demand is the forecast consumption based on the forecast number of vehicles served by the vehicle fueling station.

12B.5 **Costs** - The total costs to be used in determining the forecast cost of service to be recovered from the Customer under the Service Agreement include, without limitation

(a) the capital investment, including any associated labour, material, capitalized overhead and other costs necessary to serve the Customer, less any contributions in aid of construction by the Customer or third parties, grants, tax credits or non-financial factors offsetting the full costs that are deemed to be acceptable by the British Columbia Utilities Commission;

(c) depreciation expense related to the capital assets associated with the vehicle fueling station; and

(d) the incremental operating and maintenance expenses necessary to serve the Customers.

In addition to the costs identified, the cost of service recovery will include applicable property and incomes taxes and the appropriate return on rate base as approved by the British Columbia Utilities Commission.

Scope of Two Year Test Period Report on CNG LNG Service

The reporting period for the purposes of the report shall be fiscal 2011 and 2012 and the report shall be filed with the Commission by March 31, 2013.

The scope of the review and the report shall include the following:

1) CNG LNG Service to date
   a) Provide a List of CNG LNG Service Tariff Supplements executed with details regarding name of customer, location of refuelling station, number of vehicles in fleet, take-or-pay quantities, volumes delivered, rate, term of contract, capital costs, and operating and maintenance costs
   b) For each CNG LNG Agreement, provide a comparison of actual and forecast capital costs, revenues and expenses by month for CNG LNG Service for 2011 and 2012
   c) Quantify costs and benefits for other ratepayers for 2011 and 2012

2) Cost of Service
   a) Provide updates to the cost of service model inputs and explain any changes
   b) Provide rate base, depreciation/amortization and deferral account continuity schedules

3) Updated CNG LNG Market Forecasts for 5, 10, 15 and 20 years out
   a) Forecast CNG LNG Service market share
   b) Forecast annual CNG LNG Service volumes
   c) Forecast CNG LNG Service costs and revenue

4) Nature and Evolution of CNG LNG Service Agreements Executed To Date.

   In particular, provide details regarding:
   a) Range and types of terms incorporated in agreements negotiated to date
   b) Describe trends in standard terms of CNG LNG Agreements
   c) Feasibility of implementing Pro Forma Tariffs for CNG LNG Service

5) Deferral Account Update
   a) Report details of costs for all deferral accounts related to CNG LNG Service
   b) Describe any approved changes to such deferral accounts
   c) Describe any proposed changes to deferral accounts

6) Current Status of NGV sector in British Columbia
   a) Address the ongoing need for FEI to "kickstart" the return–to-base fleet NGV sector
   b) Identify remaining barriers to NGV uptake
   c) Discuss ongoing need for economic incentives
   d) Identify any technological threats (e.g. switching to electric hybrids)

e) Identify extent to which NGV refuelling stations are provided by suppliers other than FEI (number of stations, quantities, number and type of vehicles)

7) Natural Gas /Diesel Price Forecasts

a) Provide update on natural gas supply and pricing

b) Provide update on diesel/ natural gas price differentials

8) LNG Supply

a) Provide update on LNG supply availability and reliability of supply for LNG Service customers

b) Provide update on status of Rate Schedule 16 (e.g. approval of pilot, rate changes, volume restrictions)

c) Comment on any need to expand Tilbury (timing, cost and nature of any required expansion)

d) LNG tanker truck service (rate, cost, need for additional tankers, extent to which service is provided by FEI)

e) Impact of LNG Service on LNG Peaking reliability, availability and cost of service for other ratepayers

f) Role of Mt Hayes Facility in supply of LNG to LNG Service customers

9) LNG Standards and Codes

a) Provide an update on status of development of LNG Codes and Standards

b) Describe impact of new /revised codes on facility design and operation

c) Provided estimate of any cost impact related to changes in standards and codes

10) Update of Fully Allocated Cost of Service

a) Provide revenues and load factors for the rate classes relevant to CNG LNG Service (e.g. CNG LNG Service, Rate Schedule 16, Rate 25)

b) Provide estimates of the cost of serving new CNG LNG Service customers with a description of methodology

c) Compare revenue to cost ratios for all rate classes as compared to earlier years before implementation of CNG LNG Service

11) Ownership of Carbon Credits

a) Describe current status on treatment of carbon credits associated with CNG LNG Service

b) Provide update on FEI role in supporting third party validation and verification

c) Provide update on current cost/value of carbon

12) Incentive Funding

a) Status of incentive funding for NGVs

b) Amount of funding awarded for NGVs

c) Ongoing need for incentive funding in NGV sector

d) Identification of other potential or existing suppliers of incentive funding

13) Government policy impacting NGV sector

a) Provincial policy impacts

b) Federal policy impacts

c) Municipal policy impacts

14) NGV Regulations

a) Identify any government regulations related to CNG LNG Service

b) Describe the impact of the regulations on CNG LNG Service and the NGV market

British Columbia Utilities Commission

Order Number G-145-11

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

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

and

FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc.
Energy Efficiency and Conservation Program
Natural Gas Vehicle Incentives Review

BEFORE: A.A. Rhodes, Panel Chair /Commissioner
D.A. Cote, Commissioner
M.R. Harle, Commissioner

August 15, 2011

O R D E R

WHEREAS:

A. On March 31, 2011, FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc. (FEI/FEVI, the Companies) submitted their Energy Efficiency and Conservation (EEC) Program 2010 Annual Report as a compliance filing in accordance with British Columbia Utilities Commission (Commission) Order G-36-09. In the cover letter to the Report, FEI/FEVI request the Commission address the Companies' use of EEC funds as incentives for Natural Gas Vehicles (NGVs) at the earliest possible date;

B. On April 18, 2011, the Commission issued Letter L-30-11 which indicated the Commission would initiate a regulatory process to review and determine the appropriateness of the Companies' use of EEC funds as NGV incentives (the Review Proceeding). The following specific questions were posed:

1. Was it appropriate for the Companies to change the scope of the Innovative Technologies program to include NGV purchase incentives via the EEC Stakeholder Group and the EEC Program-2009 Report (filed March 31, 2010)?

2. If the scope of the Innovative Technologies program was appropriately changed, does the associated NGV purchase funding become:

   a. a Commission-approved expenditure; or
   b. an approved EEC expenditure; or
   c. an expenditure eligible for cost recovery from ratepayers in whole or in part?

3. If NGV purchase incentive funding is found to be inappropriately included in the Innovative Technologies program, should incentive payments already made by the Companies be eligible for cost recovery from ratepayers in whole or in part?

C. By Order G-70-11 dated April 20, 2011, the Commission established a Regulatory Timetable for the written hearing of the Review Proceeding;

D. On June 3, 2011, following its receipt and review of the submissions of the Companies and Interveners, the Commission Panel sought further submissions from the parties on the additional issue of:

- the ability and appropriateness of the utility moving EEC funds among programs that meet the definition of "demand-side measure" in the *Utilities Commission Act* and programs that do not

and established an amended Regulatory Timetable for that purpose;

E. The written process for the Review Proceeding concluded with the filing of the Companies' Reply Submission on June 16, 2011;

F. The Commission Panel has reviewed the evidence and submissions of the Parties.

NOW THEREFORE for the Reasons attached hereto as Appendix A**,** the Commission:

1. Determines that, in answer to Question 1, it was not appropriate for the Companies to change the scope of the Innovative Technologies program to include NGV purchase incentives via the EEC Stakeholder Group and the EEC Program–2009 Report (filed March 31, 2010). It further determines that the NGV program is not a demand-side measure within the meaning of the *Clean Energy* and *Utilities Commission Acts*.

2. Directs that FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc. are to include only those expenditures meeting the definition of "demand-side measure" as found in the *Clean Energy* and *Utilities Commission Acts*, as determined by the Commission Panel in the attached Reasons for Decision, in the Energy Efficiency and Conservation category. Programs which do not meet the definition are to be kept separate. This applies as well to any funding for "technology innovation programs".

3. Provides FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc. and Interveners the opportunity to file further submissions on the issue of the prudency of the NGV incentive expenditures, given the findings of the Commission Panel as set out in the Reasons attached hereto as Appendix A, in accordance with a timetable to be arranged.

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of August 2011.

BY ORDER

Original signed by:

A.A. Rhodes
Panel Chair/Commissioner

Attachment

IN THE MATTER OF

FORTISBC ENERGY INC./
FORTISBC ENERGY (VANCOUVER ISLAND) INC.
ENERGY EFFICIENCY AND CONSERVATION
NATURAL GAS VEHICLE INCENTIVE REVIEW

REASONS FOR DECISION

August 15, 2010

BEFORE:

A.A. Rhodes, Panel Chair / Commissioner
D.A. Cote, Commissioner
M.R. Harle, Commissioner

TABLE OF CONTENTS

PAGE NO.

1.0 INTRODUCTION

FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc. (the Companies) are related regulated public utilities engaged primarily in the distribution of natural gas through the provision of sales and transportation services to over 900,000 residential and commercial customers in over 100 communities in British Columbia, including Vancouver Island.

The Companies have recently significantly increased their spending of "Energy Efficiency and Conservation" funds (which are provided by ratepayers) to finance programs in the area of Natural Gas Vehicles (NGVs). This spending relates to the provision of incentive payments to select large customers to assist them to purchase Natural Gas Vehicles in lieu of vehicles fuelled by diesel.

This Review Proceeding was initiated to assess the appropriateness of this activity, in light of the history set out below.

Specifically, this Review Proceeding was initiated on April 18, 2011 to examine three questions:

1. Was it appropriate for the Companies to change the scope of the Innovative Technologies program to include NGV purchase incentives via the EEC Stakeholder Group and the EEC Program- 2009 Report (filed March 31, 2010)?

2. If the scope of the Innovative Technologies program was appropriately changed, does the associated NGV purchase incentive funding become: (a) a Commission-approved expenditure; or (b) an approved EEC expenditure; or (c) an expenditure eligible for cost recovery from rate payers in whole or in part?

3. If NGV purchase incentive funding is found to be inappropriately included in the Innovative Technologies program, should incentive payments already made by the Companies be eligible for cost recovery from rate payers in whole or in part?

(Commission Letter L-30-11; FEI/FEVI EEC Natural Gas Vehicle Incentive Review Proceeding; Exhibit A-1)

2.0 BACKGROUND

The Companies have had programs in place relating to demand-side management and the promotion of energy efficiency for a number of years. Traditionally, expenditures for these programs have been assessed as part of the Revenue Requirements Applications. The Companies' demand-side management activity was relatively constant from the late 1990s to 2007, involving total expenditures for both incentives and non-incentive expenses for both Companies of less than $5.0 million per year over that time period.

2.1 Energy Efficiency and Conservation Programs Application

In May of 2008, the Companies filed their "Energy Efficiency and Conservation Programs" Application which sought approval of increased expenditures (of $56.6 million for both Companies for three years) in support of an expanded energy efficiency and conservation (EEC) strategy. The Companies also sought to increase the amortization period for incremental EEC expenditures to 20 years [from 3 years for FortisBC Energy Inc. (FEI) and 1 year for FortisBC Energy (Vancouver Island) Inc. (FEVI)].

One area of proposed expansion in the EEC Application was "Innovative Technologies, NGV and Measurement Program Area" which requested a total of $3.0 Million. The projects described in "NGV- Natural Gas Vehicle projects" included "utilizing liquefied natural gas in heavy-duty vehicle applications or utilizing renewable or hydrogen in combination with natural gas in specific transportation applications". The notion of providing vehicle grants to customers not otherwise eligible for grants under Rate Schedule 6 through a vehicle grant fund was also raised. Other NGV projects identified in this section included: Hydrogen/Compressed Natural Gas blended projects (HCNG) and Biogas vehicles. (Exhibit A2-2, Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. EEC Application, pp. 14-15; 75-76)

In its Decision on the EEC Application of April 16, 2009, (the EEC Decision) the Commission Panel rejected all proposed expenditures in this area. It found that "Innovative Technologies, NGV and Measurement programs can be appropriate vehicles for encouraging commercial development of technologies to reduce or replace natural gas consumption and related GHG emissions". It also noted the acknowledgement of FEI that further refinement of the program was required and found that there was insufficient evidence as to the nature and scope of the proposed program. The Panel commented that FEI might wish to bring forward projects in this program area for consideration as they become more fully developed. (Exhibit A2-3, EEC Decision, p. 26)

2.2 2010-2011 Revenue Requirements Application

On June 15, 2009 FEI filed its 2010-2011 Revenue Requirements Application.

The Table of Contents and Headings within that Application are clear in their classification of Natural Gas Vehicle offerings within "Alternative Energy Solutions", as separate and distinct from "Energy Efficiency and Conservation Programs" under which "Innovative Technologies" were shown as a subsection of "Industrial Energy Efficiency". (Exhibit A2-4, Terasen Gas Inc. 2010-2011 Revenue Requirements Application, p. iii)

The technologies described in the "Innovative Technologies" subsection were:

- Hydronic Based Heating Systems
- Integrated Energy Systems (or Combinations Systems)
- Solar Thermal
- Ground Source Heat Pumps

(Exhibit B-1, BCUC IR 1.6.2)

The 2010-2011 RRA was determined by way of a Negotiated Settlement Process.

<u>2.2.1 Negotiated Settlement Agreement</u>

The Negotiated Settlement Agreement which was approved by Commission Order G-141-09 dated November 26, 2009, states the following with respect to Natural Gas Vehicles:

"14. <u>Natural Gas for Vehicles ("NGV")</u>

The Commission Issue No. 2 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

"Natural Gas Vehicles ("NGV") – if NGV is to proceed why should the natural gas ratepayer fund this initiative rather than Terasen's non-regulated businesses or the competitive market?"

The Parties agree:

(a) NGV Rate Schedule 26 – NGV Transportation Service should be approved as filed.

(b) The marketing costs in support of NGV that are included in the revenue requirements Application are appropriately recoverable in 2010 and 2011 rates.

(c) Upon acceptance of this Agreement by the Commission, TGI withdraws its request in this Application for the following:

i. Rate Schedule 6C NGV Compression and Refueling Service and 6A NGV Refueling Service; and
ii. the Compression Service ("CS") Test; and
iii. NGV non-rate base deferral account.

The Parties acknowledge that these requests are being withdrawn by TGI to facilitate a settlement on other issues presented in this Application. The Parties agree that TGI's withdrawal of its requests regarding NGV is without prejudice to TGI's right to bring forward similar requests in 2010 or 2011 or otherwise in the future. The Parties acknowledge that TGI intends to develop this area of business and that TGI anticipates it will bring forward applications on NGV projects to the Commission on a case-by-case basis during the term of this Agreement and in future years. The Parties agree that TGI is at liberty to do so."

(Exhibit A2-5, Terasen Gas Inc. 2010-2011Revenue Requirements Application, Negotiated Settlement Agreement, p. 9)

2.3 Application for Approval of Service Agreement for Compressed Natural Gas

On December 01, 2010 FEI applied to the Commission for, *inter alia*, approval of a draft agreement which it had made with Waste Management of Canada Corporation for compression and dispensing service for Compressed Natural Gas. It also applied for acceptance of the expenditures required to provide the service as well as approval of General Terms and Conditions for use in future contracts, for both CNG and LNG customers. FEI specifically stated that it was "not seeking approvals for Energy Efficiency and Conservation (EEC) funding, O&M funding for NGV business development, or any costs that are intended to be recovered from existing natural gas customers". However, the Application did indicate that FEI had provided incentive funding to Waste Management to cover the incremental cost of purchasing 20 natural gas vehicles, as opposed to their diesel equivalents. This funding was in the approximate amount of $803,000 or slightly more than $40,000 per vehicle. (Application for Approval of Service Agreement for Compressed Natural Gas Exhibit B-1, p. 47; EEC Natural Gas Vehicle Incentive Review, Exhibit B-1, BCUC IR 1.7.2)

In its January 14, 2011 Reasons for Decision approving the Waste Management Agreement on an interim basis, the Commission Panel questioned whether FEI had approval to make the incentive payments to Waste Management outside those contemplated in existing Rate Schedules, given the explicit rejection of expenditures in that area in the EEC Decision as well as the withdrawal of requests relating to NGVs in the Negotiated Settlement Agreement (NSA).

2.4 Energy Efficiency and Conservation Programs 2010 Annual Report

During 2010 FEI committed a total of $5.587 million in incentives for NGVs. Future commitments are expected to amount to a further $3.78 million. (Future commitments are those where, *inter alia*, there has been an application by the customer, but no agreement with the customer has been signed.) (Exhibit B-1, BCUC IR 1.7.1; 1.7.1.1)

In their 2010 EEC Programs Annual Report, the Companies took the position that they had acted within the guidelines and approvals of past regulatory decisions for EEC funding for NGVs and sought Commission concurrence on the issue, in an expedited fashion, prior to the 2012-2013 Revenue Requirements Application. The Companies took the further position that the use of Innovative Technologies Program Area EEC funding for NGV initiatives is consistent with past Commission Orders. (2010 EEC Annual Report pp. 201-203)

It is not suggested that further stakeholder engagement or compliance reporting can alter the overall scope of an accepted expenditure schedule. As noted by the Companies, "[o]nly the Commission has the ability to accept EEC expenditures pursuant to section 44.2... For clarity, the stakeholder engagement process is a consultation exercise, not an approval process. The EEC Annual Report is a compliance reporting. Neither the mere consent of the EEC stakeholder group, nor the inclusion of information in a compliance report to the Commission, can alter the overall scope of an accepted expenditure schedule". (FEI and FEVI Final Submissions, pp. 5-6)

3.0 FEI/FEVI ENERGY EFFICIENCY AND CONSERVATION NATURAL GAS VEHICLE INCENTIVE REVIEW PROCEEDING

As noted previously, this Review Proceeding was initiated to examine three questions, the first of which is:

3.1 Question 1

Was it appropriate for the Companies to change the scope of the Innovative Technologies program to include NGV purchase incentives via the EEC Stakeholder Group and the EEC Program- 2009 Report (filed March 31, 2010)?

The Companies submit that the inclusion of additional spending in the area of NGVs was properly within their discretion as contemplated by the framework established in the EEC Proceeding. That framework contemplated the Companies' ability to re-allocate funds among approved program areas within the overall portfolio. (FortisBC Energy Utilities Submission, pp. 6-9)

The Companies admit that the programs identified in the "Innovative Technologies" section of the 2010-2011 RRA did not include NGVs. They further admit that in another program area, [Alternative Energy Solutions], certain specific requests with respect to NGVs were approved, but the other remaining requests were withdrawn. Notwithstanding these admissions, the Companies submit that NGVs share the same fundamental objectives and characteristics as the other programs within the Innovative Technologies area such that the approval of the Innovative Technologies Program Area was the only approval necessary. (FortisBC Energy Utilities Submission, pp. 10-11)

The Companies further submit that the scope of the Innovative Technologies Program Area approved in the NSA must be viewed in context, which context includes the EEC Application where the Companies described potential areas of opportunity and a broad range of types of initiatives having the same underlying characteristics:

1) Promoting the efficient use of natural gas through sustainable design,
2) Not being a mainstream technology,
3) Offering the potential for at least a 10% GHG reduction benefit.

The BC Sustainable Energy Association (BCSEA) supports the Companies' position. The BCSEA submits that the Commission accepted an overall expenditure envelope for EEC funding in its April, 2009 EEC Decision and therefore contemplated that the Companies would have the ability to move funding among program areas without additional Commission involvement. It further submits that approval of "Innovative Technologies" as a program area in the 2010-2011 RRA NSA contemplated that new programs would be added. (BCSEA Final Submission, pp. 4-6) BCSEA further submits that the Commission's approval of the Companies' 2010-2011 RRA NSA, (where the program area for Innovative Technologies was approved, without reference to NGVs) did "not imply anything negative about NGV incentive funding." (BCSEA Final Submission, p. 6) Further discussion of NGVs was with stakeholders, which BSCEA considers appropriate. (BCSEA Final Submission, pp. 6-7)

The Commercial Energy Consumers Association of British Columbia (CEC) also supports the Companies' position. The CEC argues that the scope of the Innovative Technologies Program Area is defined by the objectives of the program as opposed to by a list of specific initiatives within it. It submits that the initial rejection of the Program Area in the EEC Decision was temporary and notes the invitation of the Commission Panel for FEI, which was "to bring forward projects in this program area for consideration as they become more fully developed." (CEC Final Submission, p. 2; EEC Decision, p. 26) The CEC further submits "that the [Companies] have not changed the scope of the Innovative Technologies Program Area but have added the NGV Incentives funding program to the suite of programs in the Innovative Technologies Program Area. (CEC Final Submission, p. 5) It argues that the Companies have shown the NGV Purchase Incentive Funding is cost-effective, which supports the contention that this funding is in the public interest. It recommends that the Commission find the addition of the NGV Incentive Funding program to the Innovative Technologies Program Area was appropriate and met the objectives of that Program Area as well as EEC objectives generally. (CEC Final Submission, p. 6)

Commission Panel Determination

The Commission Panel finds that the Companies did not have approval to use EEC monies to provide incentives for NGVs.

The Commission Panel notes at the outset that the EEC Decision specifically rejected the entire area of "Innovative Technologies, NGVs and Measurement".

Further, in the EEC application, although LNG in heavy-duty vehicle applications was mentioned, the Companies did not advance compressed natural gas vehicles as an "innovative technology", as is now suggested. Rather, at that time, the Companies noted that "[u]nlike conventional Compressed Natural Gas ("CNG") vehicles, new technology is emerging whereby hydrogen is blended at the pump with compressed natural gas...HCNG is one of the most promising near-term opportunities for utilizing hydrogen in vehicles and moving towards a more hydrogen driven economy. As hydrogen burns cleaner than natural gas, further emission reductions are gained and 10-20% GHG reductions over CNG can be achieved. Other HCNG initiatives may include fuel for trains, fleets and other vehicle applications." (EEC Application, Exhibit B-1, pp. 75-76)

As well, in the Commission Panel's discussion and subsequent rejection of this category of expenditure it indicated that "Innovative Technologies, NGV and Measurement programs can be appropriate vehicles for encouraging commercial development of technologies *to reduce or replace natural gas consumption*..." but that there was insufficient evidence of the nature and scope of the proposed program to warrant approval. (emphasis added). (EEC Decision, p. 26)

In the subsequent 2010-2011 Revenue Requirements Application, NGVs were again brought forward, this time as part of "Alternative Energy Solutions". The Commission Panel specifically raised concerns about NGVs and requested that these concerns be addressed in the Negotiated Settlement Process. As a result, in the end, the NSA provided approval for two items, being new Rate Schedule 26 and recovery of what were described as "modest" marketing costs incurred in support of NGVs in 2010-2011 rates. The remaining items for which approval was sought, which included an NGV non rate base deferral account, were withdrawn.

New Rate Schedule 26, "NGV Transportation Service" which was approved as part of the NSA, included "Special Conditions" basically identical to the "Special Conditions" found in existing Rate Schedule 6 "Natural Gas Vehicle Service". These Special Conditions contemplate a maximum incentive payment for the purchase of or conversion to a heavy duty natural gas vehicle of $10,000.00 per vehicle. To the extent that it can be suggested that incentive grants were contemplated in that NSA, the amounts put forward were limited, and consistent with grant amounts already on offer.

The Compression Service Tariff, the request for approval of which was withdrawn as part of the NSA, contemplated capitalization of costs once a potential customer executed a contract for the provision of compression service, and deferral account treatment of those costs, as well as ongoing operating and maintenance costs related to the delivery of energy. (TGI 2010-2011 RRA Exhibit B- 4, BCUC IR 1.21.1)

The Commission Panel disagrees with the suggestion that approval of the Innovative Technologies Program area could in any way be considered approval of EEC funding for NGVs. In fact, in its answers to Information Requests in the 2010-2011 Revenue Requirements Application, FEI emphasized that its EEC requests were different than those relating to Alternative Energy Solutions. It stated that "...it is important to distinguish between the requests in this Application regarding EEC and those pertaining to Alternative Energy Solutions [under which approval was sought for NGVs]....EEC programs and expenditures primarily related to activities to reduce energy usage via incentives, education and audits etc. They do not include the ownership of alternative energy equipment." (TGI 2010-2011 RRA, Exhibit B- 4, BCUC IR 1.21.1) FEI further confirmed that "...Innovative Technologies are an EEC program (i.e. not one of the Alternative Energy Solutions) whereby customers will receive incentives for Hydronic Heating Systems, Integrated Energy Systems, Solar Thermal and Ground Source Heat Pumps." (TGI 2010-2011 RRA, Exhibit B-4, BCUC IR 1.23.1.2)

Moreover, in the Panel's view, the Innovative Technologies Area as set out in the 2010-2011 Revenue Requirements Application did not share the same characteristics as the NGV area, as is now suggested by FEI. The Innovative Technologies put forward included measures to reduce natural gas consumption, not increase it, as is the case for NGVs.

Even if it could be argued that it was open to move/add program areas with similar objectives etc., which argument is not accepted given the specific rejection of NGVs in both applications– and particularly given the express concern of the Commission Panel – the underlying characteristics are not the same.

The Panel does not accept that the Companies were justified in assuming that approval of the Innovative Technologies category was a green light to proceed with NGV initiatives. FEI confirmed in its November 13, 2009 letter to the Commission responding to staff's comments on the NSA that it had an existing NGV tariff and the amount of the marketing costs in the revenue requirements for 2010 and 2011 [which were accepted in the NSA] were "very modest". It also confirmed that "[*i]ssues relating to NGV have been deferred by the terms of the Settlement Agreement".* (emphasis added) In the Panel's view, this latter statement indicated that FEI was proposing to make a further application to the Commission prior to committing EEC funds to NGV initiatives.

However, no other applications concerning EEC funding for NGV initiatives were made. In that regard, the Commission Panel agrees with the Companies that the stakeholder engagement process is a consultation exercise, not an approval process and the EEC Annual Report is a compliance reporting such that "[n]either the mere consent of the EEC stakeholder group, nor the inclusion of information in a compliance report to the Commission, can alter the overall scope of an accepted expenditure schedule". (FEI and FEVI Final Submissions, pp. 5-6)

Accordingly, the Commission Panel answers Question 1 "Was it appropriate for the Companies to change the scope of the Innovative Technologies program to include NGV purchase incentives via the EEC Stakeholder Group and the EEC Program- 2009 Report (filed March 31, 2010)?" in the negative.

3.2 Question 2

If the scope of the Innovative Technologies program was appropriately changed, does the associated NGV purchase incentive funding become: (a) a Commission-approved expenditure; or (b) an approved EEC expenditure; or (c) an expenditure eligible for cost recovery from rate payers in whole or in part?

It is not necessary to consider this question given the Panel's answer to Question 1.

3.3 Question 3

If NGV purchase incentive funding is found to be inappropriately included in the Innovative Technologies program, should incentive payments already made by the Companies be eligible for cost recovery from rate payers in whole or in part?

In response to Question 3, the Companies submit that the Commission must set rates so as to allow the utility to recover the forecast costs for the test period that the Commission reasonably considers will be prudently incurred. The Companies further submit that a finding that the NGV-related expenditures were not approved as part of the Innovative Technologies Program Area does not amount to a finding of imprudence, simply a finding that there has been no prior approval under s. 44.2 of the Act, which they argue is optional in any event. Finally, the Companies submit that, in the absence of a s. 44.2 acceptance, the prudence of the expenditure must still be determined, having reference to the costs and benefits associated with the activities. They submit that the NGV-related expenditures to date are in the public interest and the forecasted amortization expense associated with the expenditures should be eligible for recovery as a prudent expenditure.

3.4 Demand-side Measures

Given the above submissions on section 44.2 which states (in part):

> (1) A public utility may file with the commission an expenditure schedule containing one or more of the following:
>
> > (a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;

(b) a statement of capital expenditures the public utility has made or anticipates making during the period addressed by the schedule;...

(2) The commission may not consent under section 61 (2) to an amendment or a rescission of a rate schedule filed under section 61(1) [which requires public utilities to file schedules showing all rates] 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 [being expenditures on demand-side measures], 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,

the Commission Panel requested additional submissions on the ability and appropriateness of the utility moving EEC funds among programs that meet the definition of "demand-side measure" in the *Utilities Commission Act* and programs that do not. (Exhibit A-6)

The definition of Demand-Side Measure is found in the *Clean Energy Act* SBC 2010 c.22 s. (1) (1) and means:

a rate, measure, action or program undertaken

(a) to conserve energy or promote energy efficiency,

(b) to reduce the energy demand a public utility must serve, or

(c) to shift the use of energy to periods of lower demand,

but does not include

(d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or

(e) any rate, measure, action or program prescribed.

The Companies take the position that the NGV Program meets the definition of "demand-side measure" in the Act. They state that the NGV Program was undertaken to "promote energy efficiency". The Companies submit that the term "promote energy efficiency" must be different than "conserve energy" and therefore the concept of "using the right fuel for the right activity" is relevant. The Companies submit that this broader concept includes a variety of perspectives such as system utilization, economics, and reduction of Greenhouse Gases.

FEI and FEVI further submit that because the definition of "demand-side measure" specifically excludes "programs which encourage a switch from one kind of energy to another such that the switch would *increase* GHG emissions in B.C." the fact that this fuel-switching activity has the effect of reducing GHG emissions may qualify it as a demand-side measure.

They also argue that "[t]he NGV Program is efficient from the perspective of the use of energy resources and delivery systems in the province. ... As the NGV demand is a relatively flat year-round load, it increases natural gas use in the lower demand summer period,..." thereby shifting the use of energy to periods of lower demand. (Exhibit B-4, FEI/FEVI Submission on Exhibit A-6, pp. 2-3)

The BCSEA agrees with the Companies that the NGV Incentives Program meets the definition of a "demand-side measure" on the basis that the Program is undertaken to "promote energy efficiency". It argues that the legislation does not require that such a program have the exclusive objective of conservation or energy efficiency and that there may be additional purposes. It also argues, as do FEI and FEVI, that, as the definition of "demand-side measure" does not specifically exclude fuel-switching programs that decrease GHG emissions, the legislation therefore contemplates DSM programs that can have GHG emissions benefits through fuel-switching. The BCSEA further takes the position that, as the reduction of GHG emissions is one of British Columbia's energy objectives, and the Commission must consider British Columbia's energy objectives in reviewing a demand-side measure expenditure, the fact that this program has a substantial purpose of reducing GHG emissions increases its desirability as a demand-side measure. It further argues that what is important is the evaluation of the merits of a DSM program, not whether it meets the definition of the same, and that an inclusive approach to the definition does no harm, whereas applying the definition so that it serves a “gate-keeping’ function serves no policy purpose. The BCSEA further argues that if the NGV program was not eligible for public interest acceptance under section 44.2 of the *Utilities Commission Act* (as either a demand-side measure or possibly a capital expenditure), there would be a gap, and there would be “no obvious way for such a program to be proposed by a public utility and the expenditures accepted (or not) by the Commission”. Finally, the BCSEA argues that it is important that all putative DSM programs be included in a DSM portfolio so that any benefits of a program in terms of maintaining a positive benefit-cost ratio not be lost.

The CEC supports the submissions of the BCSEA. It further supports the ability of the Companies to move EEC funds among programs in the interests of administrative efficiency. It confirms that, in its view, the risk of inappropriate or imprudent movement of funds between DSM and non-DSM programs is one the Company faces in subsequent prudency reviews and that ultimately, an improper or imprudent movement of funds will be a risk to the shareholder.

Commission Panel Determination

The Commission Panel finds that the NGV program is not a “demand-side measure” as defined in the *Clean Energy Act*.

Reduction in greenhouse gases, although a laudable goal, and a goal which is recognized in the *Clean Energy Act*, is not, in the Panel’s view tantamount to “conservation” or “energy efficiency”. The Commission Panel agrees with FEI that the terms “conservation” and “energy efficiency” must be accorded different meanings. However, in the Panel’s view, on a plain meaning, the term “conservation” implies using less [energy], and “energy efficiency” is a similar but different concept which implies doing the same task, while using less energy. For example, to conserve energy a person might turn off a light or turn down his/her thermostat. To be energy efficient, that same person might switch to a light bulb which, although providing equivalent light, uses less energy to do so, or switch to a furnace which uses less energy to produce the same amount of heat. Reducing GHGs is not one of the objects of the definition of a demand-side measure, but will often flow as a natural and inevitable consequence when demand-side measures are taken.

This meaning is also consistent with the greater context of both the *Clean Energy Act* and the *Utilities Commission Act*.

As noted above, the goal of reducing greenhouse gas emissions is recognized in a number of the specific energy objectives contained in the *Clean Energy Act*. However, the objectives relating to the reduction of greenhouse gases are separate and distinct from those relating to demand-side measures. In the Panel’s view, the legislature uses both terms and had it sought to include a measure designed to reduce greenhouse gases in its definition of demand-side measures it could and would have done so.

Further, under s. 44.1 of the *Utilities Commission Act* a public utility’s long-term resource plan must be filed and must include an estimate of the demand it expects to serve absent demand-side measures and how it expects to reduce that demand by taking cost-effective demand-side measures. This underscores the fact that demand-side measures are directed at reducing energy consumption, not building load.

In terms of energy efficiency, natural gas is not more energy efficient than gasoline or diesel. It is, in fact, less efficient than diesel by a factor of 10-20%. FEI used a 17% fuel efficiency loss in its economic analysis relating to the conversion of vehicles in the Waste Management fleet, a related application. (Application for Approval of a Service Agreement for Compressed Natural Gas Service and for Approval of General Terms and Conditions for Compressed Natural Gas and Liquified Natural Gas Service Exhibit B-1, p. 50, FN 59; p. 51, FN 61; Exhibit B-8 BCSEA IR 2.3.1)

In the Panel’s further view, the definition is clear that demand-side measures relate to the use of “energy” itself and not the infrastructure used to deliver it.

The Panel also does not agree with FEI/FEVI or the Interveners that the specific exclusion of "a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia" as set out in subsection (d) of the definition of "demand-side measure" can be interpreted to allow for the inclusion of an item which was never included in the definition in the first instance. In the Panel's view, the definition of "demand side measure" does not mean anything other than what is set out in subsections (a), (b), and (c) of the definition. Rather, excluded items (d) and (e), add clarity but do not, by implication, extend the definition beyond the measures contemplated in items (a), (b), and (c).

In the Panel's view, item (d) would be relevant to a program which met the definition of "demand-side measure" as set out in either items (a), (b), or (c) in the first instance, but which then fell afoul of the exclusions. For example, a program designed to have electricity consumers in British Columbia switch from purchasing electricity from BC Hydro to heat their houses to purchasing natural gas for the same purpose would "reduce the energy demand that a public utility [BC Hydro] must serve', but would then be excluded from the definition due to the fact that it would increase greenhouse gas emissions in British Columbia. Conversely, a program designed to have natural gas consumers in British Columbia switch from purchasing natural gas to heat their houses to purchasing electricity for the same purpose would "reduce the energy demand that a public utility [the natural gas provider] must serve, and would also decrease GHG emissions such that the exclusion would not apply.

The NGV program also fails to meet items (b) and (c) of the definition of demand-side measures.

Item (b) contemplates a reduction in the demand a utility must serve, and the NGV program does the opposite.

Item (c) contemplates shifting the use of energy to periods of lower demand. The Commission Panel does not accept FEI's argument that an increased load on the delivery system during the summer months can be viewed as "shift[ing] the use of energy to periods of lower demand". In the Panel's view, meaning must be given to the word "shift", which contemplates an equivalent reduction in load during periods of higher demand. In the Panel's view, this definition contemplates a measure such as "Time of Use" pricing, whereby people may be encouraged to, for example, run an appliance at night instead of during the day, when demand on the electricity system is greater.

The Panel, further, finds no merit in the BCSEA's suggestion that whether a program falls within the definition of a "demand-side measure" is of less importance than the merits of a particular program and that the definition should not serve a "gate-keeping" function. In the Panel's view, the definition of "demand-side measure" is of critical importance. The nature of an expenditure on a "demand-side measure" is unlike other expenditures a utility may make in that the expenditure is aimed at reducing the amount of product the utility sells, either generally, or during a particular time period. Expenditures on demand-side measures are therefore often accorded different treatment so as to incent the utility to make expenditures which do not serve to further its business. With respect to the BCSEA's argument that unless the NGV Program could be considered either a demand-side measure or a capital expenditure there would be a "gap" in expenditure schedules put before the Commission, the Commission Panel notes the comment of the Companies that "[f]or capital expenditures under the CPCN threshold, and for O&M generally, it is less common to have section 44.2 approval than to proceed to a revenue requirements proceeding without one". (Exhibit B-1 BCUC IR 1.9.1) In any event, the Panel does not find BCSEA's arguments, which tend to simply extoll the virtues of the NGV Program, to be of particular assistance in determining the meaning of a "demand-side measure".

The Panel therefore finds, for the reasons set out above, that the NGV Program, which is a load-building exercise, does not meet the definition of a "demand-side measure" as set out in the *Clean Energy Act* and used in the *Utilities Commission Act*.

3.5 Implications of Determination Regarding Demand-Side Measures

The Companies argue that the Commission's acceptance of their "EEC funding envelope was made pursuant to s. 44.2 (a) which applies to "demand-side measures"" but that even if funds were spent on a program which was not a "demand-side measure", this would only mean that there was no prior public interest approval, not that it was necessarily inappropriate for the expenditure to have been made. (FEI/FEVI Submission on Exhibit A-6, p. 5)

FEI/FEVI submit as well that section 44.2 acceptance is optional and that the Act does not prohibit utilities from engaging in EEC activities without prior approval from the Commission. They submit that "in the absence of a section 44.2 public interest determination, the Commission must assess the forecast amortization expenses relating to past NGV Program expenditures when setting rates for [the utilities]".

Commission Panel Determination

The Commission Panel does not agree with the Companies that in the absence of a section 44.2 acceptance of a demand-side measure expenditure the Commission must assess the forecast amortization expenses when setting rates. In the Panel's view, although filing an expenditure schedule with the Commission under section 44.2 is "optional" in that the word "may" is used [i.e. "[a] public utility *may* file with the commission an expenditure schedule..."], section 44.2 (2) suggests that if the utility is seeking to amend or rescind a rate schedule to recover expenditures referred to in subsection (1) (a) [i.e. expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule], other than on an interim basis, the Commission may not consent to the amendment or rescission unless the expenditure is the subject of a filed and accepted schedule. It is only expenditures on demand-side measures which require this prior approval, as the other types of contemplated expenditures are not subject to section 44.2(2). As noted above, in the Panel's view, expenditures on NGVs were never the subject of an accepted expenditure schedule.

However, the Commission Panel has determined that the NGV program expenditures are not demand-side measures, as defined in the *Clean Energy Act* (and carried over into the *Utilities Commission Act*). Therefore, section 44.2(2) does not apply.

3.6 Public Interest Considerations

FEI/FEVI further submit that regardless of whether the expenditures are demand-side measures, the expenditures were prudently incurred and are in the public interest and should be approved.

The Ministry of Energy and Mines - Electricity and Alternative Energy Division- intervened in support of the Companies' position and submits that the incentive grants are in the public interest.

It argues that the incentive grants are initiating a transformation of the heavy duty vehicle market in British Columbia and that such market transformation supports British Columbia's energy objectives of reducing greenhouse gas emissions and encouraging economic development and the creation and retention of jobs. The Ministry further submits that these expenditures are in the interests of the Companies' current and potential customers. The Ministry argues that the incentive grants benefit the owners of NGVs and must logically "exceed the considerable risk to fleet operations of adopting an alternative fuel..." The Ministry also adopts the Companies' position that there are long term benefits to all ratepayers through increased throughput and notes the Companies' [reference case scenario] estimate that they will achieve market penetration in the order of 30 Petajoules per year by 2030, which would provide an estimated benefit of approximately $83 million per year to all ratepayers. (Submissions of the Ministry of Energy and Mines, paras. 3, 12, 13)

The Ministry takes the position that "[a]s with most market transformation activities, some short term costs are necessary to facilitate long term benefits" and that "[s]haring of start-up costs across ratepayers is not new in the utility context." (Submissions of the Ministry of Energy and Mines, para. 14)

The Ministry also supports the model of providing incentive funding for the full incremental cost of NGVs initially, and subsequently ramping the funding down. It notes that "new technologies often have high perceived risks" due to lack of information regarding performance and concerns around the long term availability of supporting infrastructure. It further notes that "financial measures either by government or utilities can be an important tool for overcoming these barriers in the NGV market." (Submissions of the Ministry of Energy and Mines, para. 15)

The Ministry asserts that there is no other program in BC to provide incentives for heavy duty NGVs. It also expresses the view that the Companies are "filling a vital gap in the transition to widespread adoption of heavy duty NGVs". The Ministry further asserts that the Companies are best-positioned to design and run NGV incentive programs due to their familiarity with their customers' energy needs, their expertise in natural gas technology and their existing organizational capacity to run incentive programs. It submits that "the burden and opportunity of offering heavy duty NGV incentive grants should fall upon [the FortisBC Energy Utilities]." (Submissions of the Ministry of Energy and Mines, para. 16)

Commission Panel Discussion

The Commission Panel accepts that the NGV program provides benefits in that conversion of motor vehicle fleets from diesel to natural gas will reduce greenhouse gas emissions to some extent (as natural gas is not without greenhouse gas emissions) and that the reduction of greenhouse gas emissions is one of British Columbia's energy objectives. It also accepts that there may be other benefits in terms of promoting local technology and the creation of jobs.

However, it is also relevant that FortisBC Energy Inc. had approximately 830,000 customers at the time of its RRA in 2009. (Exhibit A2-4, Terasen Gas Inc. 2010-2011 Revenue Requirements Application, p. 1) FortisBC Energy (Vancouver Island) Inc. added a further approximately 100,000 customers. It is questionable whether this small customer base should fund initiatives which benefit a few select large potential customers engaged in the transportation sector, as well as all British Columbians generally through the reduction in GHG emissions. It is arguable that the funds collected from ratepayers could provide more direct benefits to those ratepayers by being used in conventional demand-side management programs which may allow those ratepayers to reduce their own consumption and, hence, their bills and which would also have the additional outcome of reducing GHGs.

3.7 Benefit to Ratepayers from Increased Throughput

The Ministry specifically notes the approximate $83 million annual savings for ratepayers which the Companies have estimated as a "long term benefit" if their "reference case scenario" market penetration comes to pass in 2030 [as expressed in 2030 dollars]. This figure has its source in the Companies' CNG/LNG Service Application, and is based on an annual volume from CNG/LNG sales to the transportation sector of approximately 29.5 million GJs of natural gas in the year 2030. The Companies described this saving: "increased throughput from the NGV fuel[l]ing service results in a favourable reduction in delivery rates for [FEI] existing natural gas customers, *all other things being equal*." (emphasis added) (CNG/LNG Application, Exhibit B-1, pp. 24-25; Appendix A-1, pp. 32-33)

In its Reasons for Decision rejecting the Companies' proposed General Terms and Conditions for CNG/LNG Service (as they failed to recover a sufficient proportion of the actual cost of CNG/LNG service from the CNG/LNG customer), the Commission Panel expressed concern as to the risks which were sought to be shouldered by FEI's existing ratepayers. These risks included the risk that there might not, in fact, be a market for CNG/LNG in the absence of incentive funding. The Panel also noted FEI's previous unsuccessful attempt to promote CNG as a transportation fuel, the costs of which were borne by its ratepayers. (CNG/LNG Application Reasons for Decision, p. 22, 30)

Aside from the uncertainty inherent in forecasts almost 20 years out, there is also considerable uncertainty surrounding the Companies' projections themselves and the "all other things being equal" assumption noted above.

3.7.1 Increased Throughput Benefit Calculation

Volume

For example, the estimates used in the projected sales of natural gas to the transportation sector of 29.5 million GJs are derived from the following projections [for the "reference case scenario"], by rate schedule:

Annual Natural Gas Volume (GJs)	**Year 2030**
Rate Schedule 6	4,201,500
Rate Schedule 16	18,680,000
Rate Schedule 25	6,668,000
Total	**29,549,500**

There is also an estimated impact to Rate Schedule 25 Demand Volume, estimated in 2030 to be 22,826 GJs.
(Source: CNG/LNG Application, Exhibit B-1, Appendix A-1, p. 34)

Delivery Rates

The incremental margin for delivery rates is calculated based on the volumes above and the delivery rates set out below:

Delivery Rates	**($/GJ)**
Rate Schedule 6	$3.648
Rate Schedule 16	$3.89
Rate Schedule 25-Delivery	$0.645
Rate Schedule 25-Demand	$15.943

(Note: The Delivery Rates which FEI used for its calculations are the existing approved rates for consistency and comparability with 2011 NSA calculations.)
(Source: CNG/LNG Application, Exhibit B-1, Appendix A-1, p. 34)

Incremental Margin at Existing Rates – 2030

The Incremental Margin is then calculated by multiplying the forecast volumes of natural gas sales in 2030 for the "reference case scenario", for each rate schedule, by the delivery rate applicable to the rate schedule. The result is the total incremental margin from increased throughput.

Incremental Margin	
Rate Schedule 6	$15,327,072
Rate Schedule 16	$72,665,200
Rate Schedule 25-Delivery	$ 4,300,860
Rate Schedule 25-Demand	$ 364,074
Total Incremental Margin	**$92,657,206**

(Source: CNG/LNG Application, Exhibit B-1, Appendix A-1, p. 34)

Net Annual Cost of Service Benefit

This incremental revenue margin of $92,657,206 for 2030 is then reduced by the forecast cost of service of the EEC Incentive Funding (which is estimated to be $10,206,000 for 2030) to arrive at the Net Annual Cost of Service Benefit, which as noted above, is calculated to be approximately $83 million in 2030. (CNG/LNG Application, Exhibit B-1, Appendix A-1, p. 33)

3.7.1.1 Forecast Volumes of Natural Gas Sales

The forecast volumes for CNG/LNG sales in the amount of 29.5 million GJs must be considered in the context of the "all other things being equal" assumption.

Rate Schedule 6 has been in effect since November of 1996, a period of almost 15 years. It is applicable to the sale of natural gas for the purpose of compression and dispensing as a fuel for the operation of NGVs. (This schedule includes the offer of a grant for customers to purchase a factory built NGV or convert a vehicle to natural gas, to a maximum of $10,000 per vehicle for a heavy duty truck.) (CNG/LNG Application, Exhibit B-1, Appendix C) The forecast volume under Rate Schedule 6 (for CNG vehicles) is 4.2 million GJs.

Rate Schedule 25 is a natural gas transportation tariff. It also relates to CNG Service and adds a further 7 million GJs to the forecast sales of natural gas for use in NGVs running on CNG. (CNG/LNG Application, Exhibit B-1, p. 24, Appendix C) Rate Schedule 25 does not offer any grant money.

Sales of LNG under Rate Schedule 16 make up 78% of the total incremental margin from the sale of natural gas to the transportation market in 2030 under the reference case scenario. (CNG/LNG Application, Exhibit B-11, BCUC IR 3.22.1.1) Rate Schedule 16 is applicable to LNG sales and dispensing service from the FEI LNG facility at Tilbury. Rate Schedule 16 was approved by the Commission as a five year pilot in 2009. This Rate Schedule defines "LNG Service" as "the interruptible service of the liquefaction, storage and Dispensing of LNG ..." This Rate Schedule is "interruptible" because the total quantity of LNG available for sale must be limited in order to avoid any potential negative impact on core customers. The maximum quantity available for sale to all LNG transportation customers is 1,040 GJs (or one tanker load) per day. Any one customer may only take delivery of 50% of the available LNG capacity in one month. The Rate Schedule contemplates that, in the event there is insufficient capacity on the FEI system to accommodate the customer's request for LNG Service, FEI may interrupt, or curtail, the LNG Service under the Schedule. (CNG/LNG Application, Exhibit B-1, Appendix C; Terasen Gas Inc. Application for Rate Schedule 16, pp. 4, 18)

As noted above, the assumption for sales of LNG under Rate Schedule 16 by the year 2030 is 18.68 million GJs in a year. This number is approximately fifty times greater than the annualized maximum daily quantity of LNG available for sale [1,040 GJs/day x 365 days/year=379,600 GJs/year] from Tilbury. The magnitude of this difference brings into question the capacity of Tilbury to accommodate even a fraction of the estimated demand for LNG in 2030 and refutes the reasonableness of the assumption "all other things being equal".

The Commission Panel is concerned that no amounts were included in the projected costs for the CNG/LNG Service Offerings for any expenditures associated with additional facilities or equipment required to provide the assumed volume of LNG. Rather, FEI took the position that "it is premature to define the extent and nature of the incremental investments in LNG assets that may be required over the next 20 years as part of [its CNG/LNG] [A]pplication". (CNG/LNG Application, Exhibit B-11, BCUC IR 3.21.4) The Commission Panel is of the view that this position serves to undermine the credibility of the Companies and their estimate of $83 million in ratepayer benefits.

The Commission Panel notes that there is, however, a new LNG storage facility, Mt. Hayes, located on Vancouver Island, which can be used to provide some guidance into the order of magnitude of the potential investment required to support the estimated 18.67 million GJs of LNG required by the transportation sector by 2030.

The Mt. Hayes facility has a storage capacity of approximately 1.6 million GJs and a liquefaction rate of somewhere in the range of approximately 8,100 GJs per day, such that it takes approximately 200 days to fill the storage tank. The CPCN for this facility was granted, subject to certain conditions, on November 15, 2007. The P90 cost estimate for this facility, as applied for, was in the order of $200 million dollars. (Terasen Gas (Vancouver Island) Inc. CPCN Application to enter into a Storage and Delivery Agreement and Terasen Gas Inc. Application to enter into a Storage and Delivery Agreement for the Mt. Hayes LNG Storage Facility (Mt. Hayes CPCN Application) Decision pp. 14-15, 21; Mt. Hayes CPCN Application, Exhibit B-1, p. 14)

The Mt. Hayes facility was constructed to provide back-up supply and peak shaving capability for the combined FEI/FEVI distribution system. It was not designed to provide direct physical supply and to do so would require the construction of a truck loading facility. FEI advises that "[t]he addition of Mt. Hayes has increased LNG storage capacity in the system by 250% and production capacity by 140%". It argues that the addition of Mt. Hayes is a factor which may warrant increasing the 1040 GJ/day limit for sales of LNG under Rate Schedule 16 currently in effect at Tilbury. (CNG/LNG Application, Exhibit B-6, BCUC IR 2.19.4)

In any event, from an order of magnitude perspective, assuming a liquefaction rate of 8,100 GJs per day, or approximately 3 million GJs per year at Mt. Hayes, and assuming Mt. Hayes could be used for LNG transportation (which, as noted above, it was neither designed nor is equipped to do), the Companies would need access to facilities with five times the liquefaction capability as Mt. Hayes, to supply the estimated 18.68 million GJs of LNG consumption by the transportation sector estimated for 2030 in the "reference case" scenario. This is not to suggest that any particular number of facilities would necessarily actually be required to be constructed or that the cost of a particular facility would equate to that of Mt. Hayes. Rather, the suggestion is that there are significant additional infrastructure requirements associated with the assumed volume of LNG consumption in 2030, the costs of which have been excluded from the analysis.

3.7.1.2 Contribution of LNG Delivery Charge

The incremental contribution of the delivery charge for the sale of a GJ of LNG to the estimated $83 million benefit in reduced delivery costs for all ratepayers is also relevant and of concern. As noted above, FEI uses the rate of $3.89 per GJ as the incremental revenue from the sale of LNG. This number is multiplied by the forecast volume of LNG sales under Rate Schedule 16 in 2030 (i.e. 18,680,000 GJs) to calculate the estimated incremental margin of $72.665 million.

It is necessary to consider the inputs to the $3.89 delivery charge per GJ of LNG to assess the validity of this critical factor input.

The $3.89 rate for LNG was originally put forward in the 2009 Rate Schedule 16 Application.

The number is derived from the following components:

O&M Charge – Liquefaction, Storage and Dispensing	$1.95 per GJ
Capital Recovery	.97 per GJ
Transportation from Huntingdon to Tilbury	.73 per GJ
Peaking Arrangement Cost	.08 per GJ
Total Variable Charge	**$3.73 per GJ**

The $3.73 number was subsequently increased to **$3.89** in accordance with approved annual rate adjustments. (CNG/LNG Application, Exhibit B-6, BCUC IR 2.25.2)

However, as FEI explains, "[p]roduction of LNG at Tilbury will generate incremental O&M cost associated with increased production of LNG at Tilbury and this cost will partially offset the revenue benefit...this incremental cost is estimated at $1.95/GJ or 52% of the rate." It is only the remaining [48%] which represents a contribution to existing costs and would provide a benefit to all ratepayers. (CNG/LNG Application, Exhibit B-6, BCUC IR 2.25.2)

Therefore, the estimated contribution of $72.665 million from LNG sales in 2030 is over-stated by a factor of more than 50%.

3.7.1.3 EEC Cost of Service

As also noted above, in order to arrive at the approximate $83 million benefit in 2030, the total incremental margin in the amount of $92.657 million is then reduced by the Cost of Service of the EEC incentive payments, which is estimated to be $10.206 million.

The EEC Cost of Service calculation, in simplified form, is based upon the EEC NGV incentive payments made, adjusted for income tax. The incentive payments, net of tax, are then accumulated in a rate base deferral account, and amortized over ten years.

The assumed Gross Additions of EEC Funding (in thousands of dollars) in intervals up to 2030 are set out below:

2011	2012	2015	2020	2025	2030
$1,100	$1,100	$2,816	$5,082	$7,062	$8,316

These additions, (net of taxes, and assuming a 10% amortization of the existing balance), result in a deferral account balance of approximately $33 million by 2030. This rate base deferral account is proposed to attract an earned return of 7.93% for FEI. (CNG/LNG Application, Exhibit B-1, Appendix A-1, p. 35)

The Cost of Service of the EEC Incentive Funding calculation is of concern in that the assumption regarding the "gross additions" of EEC funding, on which the cost of service impact is based, does not appear to align with the levels contemplated in this NGV Incentive Review.

In this NGV Incentive Review, as noted earlier, FEI's evidence is that it has spent or committed to a total of $9.367 million in incentives for NGVs for 2010 and 2011 - ($5.587 million spent in 2010 with a further expected $3.78 million in future commitments). The disparity between the assumed level of spending to calculate the cost of service (of no amount in 2010 and $1.1 million in each of 2011 and 2012) and the actual brings the usefulness of this aspect of the analysis into question as well.

Commission Panel Determination

In the Panel's view, the analysis provided by FEI to support the existence of a long term benefit to ratepayers from increased throughput on the distribution system is so flawed in terms of:

- the absence of any recognition of additional costs to provide LNG service
- the assumed contribution from the sale of LNG, and
- the assumed cost of service of the EEC incentive funding,

as outlined above, as to make the $83 million in 2030 (in 2030 dollars) result so speculative as to be deserving of no weight. **The Commission Panel finds that long term benefits to existing customers from increased throughput on the delivery system have not been established.**

As no long term monetary benefits to the Companies' existing ratepayers have been established, the Commission Panel is unable to conclude that the Companies' existing ratepayers should be contributing millions of dollars in funding to this initiative. The primary beneficiaries of the NGV incentive program are readily identifiable. They are the NGV customers who receive incentives to purchase NGVs and stand to reduce their operating costs and the Companies, which will deliver more natural gas and earn a return on the related infrastructure.

Commission Panel Determination on Recovery

Given the Panel's finding that the Companies had no prior approval to spend EEC monies on the Natural Gas Vehicle program, its finding that such expenditures are not "demand-side measures" within the meaning of the *Clean Energy Act* (and *Utilities Commission Act*), and its further finding that long term benefits to existing customers have not been established, the Commission Panel is unable to conclude that all of the expenditures in issue (totalling $9.367 million) were or will be prudently incurred and recoverable from ratepayers.

However, the Commission Panel also notes that the issue of prudency may involve additional and/or different considerations from those relating solely to the public interest, and that the issue of prudency is relevant and has not been thoroughly canvassed. The Commission Panel is therefore prepared to entertain additional submissions on the issue of prudency in respect of some or all of the expenditures in issue. Any submissions should be premised on the findings already made by the Panel.

The Panel recognizes that this Review Proceeding was initiated as a separate process to provide guidance on the issue of the provision of incentive funding for NGVs on an expedited basis. However, the Panel is concerned that the issue of prudency of the expenditures in issue has not been the subject of comprehensive submissions and is of the view that it would be fair to allow for this additional process. The Commission Panel can, however, provide some guidance on the treatment of EEC funds in the future.

4.0 EEC FRAMEWORK GOING FORWARD

The Companies have asked that the Commission provide clarification generally of the EEC process in the event that the addition of the new NGV program did not meet the Commission's intent. (FEI Final Submission, p. 10)

4.1 Separation of Demand-Side Measures Programs from other Proposed Programs

As noted earlier, and for the reasons outlined above, the Panel has determined that incentive payments for NGVs do not meet the definition of "demand-side measures" in the *Clean Energy Act*. In the Panel's view, it is important to distinguish between those programs which involve expenditures on measures which meet the definition of "demand-side measures" and others which do not. In the Panel's view these programs have different drivers and may not be amenable to the same treatment.

The Panel therefore directs that only programs or measures which meet the definition of demand-side measures, as outlined above, be included in the EEC category. Programs or measures which do not meet the strict definition should be categorized under a separate heading to avoid confusion and any expenditures, proposed or incurred, applied for separately from EEC programs or initiatives. The Panel is of the view that load-building activities should not necessarily be accorded the same treatment as is accorded demand-side measures and that this issue will need to be considered in depth. As this proceeding is limited in nature, a better forum would be the Revenue Requirements Application for 2012-2013 which was recently filed.

As well, for clarification, initiatives in Innovative Technologies or elsewhere which do not meet the definition of "technology innovation program" in the Demand Side Measures Regulation which states:

> ""technology innovation program" means a program
>
> (a) to develop a technology, a system of technologies, a building design or an industrial facility design that is
>
> (i) not commonly used in British Columbia, and
>
> (ii) the use of which could directly or indirectly result in significant reductions of energy use or significantly more efficient use of energy,
>
> (b) to do what is described in paragraph (a) and to give demonstrations to the public of any results of doing what is described in paragraph (a), or
>
> (c) to gather information about a technology, a system of technologies, a building design or an industrial design referred to in paragraph (a).

should also be kept separate from those which do. Programs or initiatives which do not meet the definition of a technology innovation program can be included with other programs or initiatives which do not meet the definition of a "demand-side measure".

BRITISH COLUMBIA UTILITIES COMMISSION

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

TABLE OF CONTENTS

Page No.

TABLE OF CONTENTS

Page No.

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)

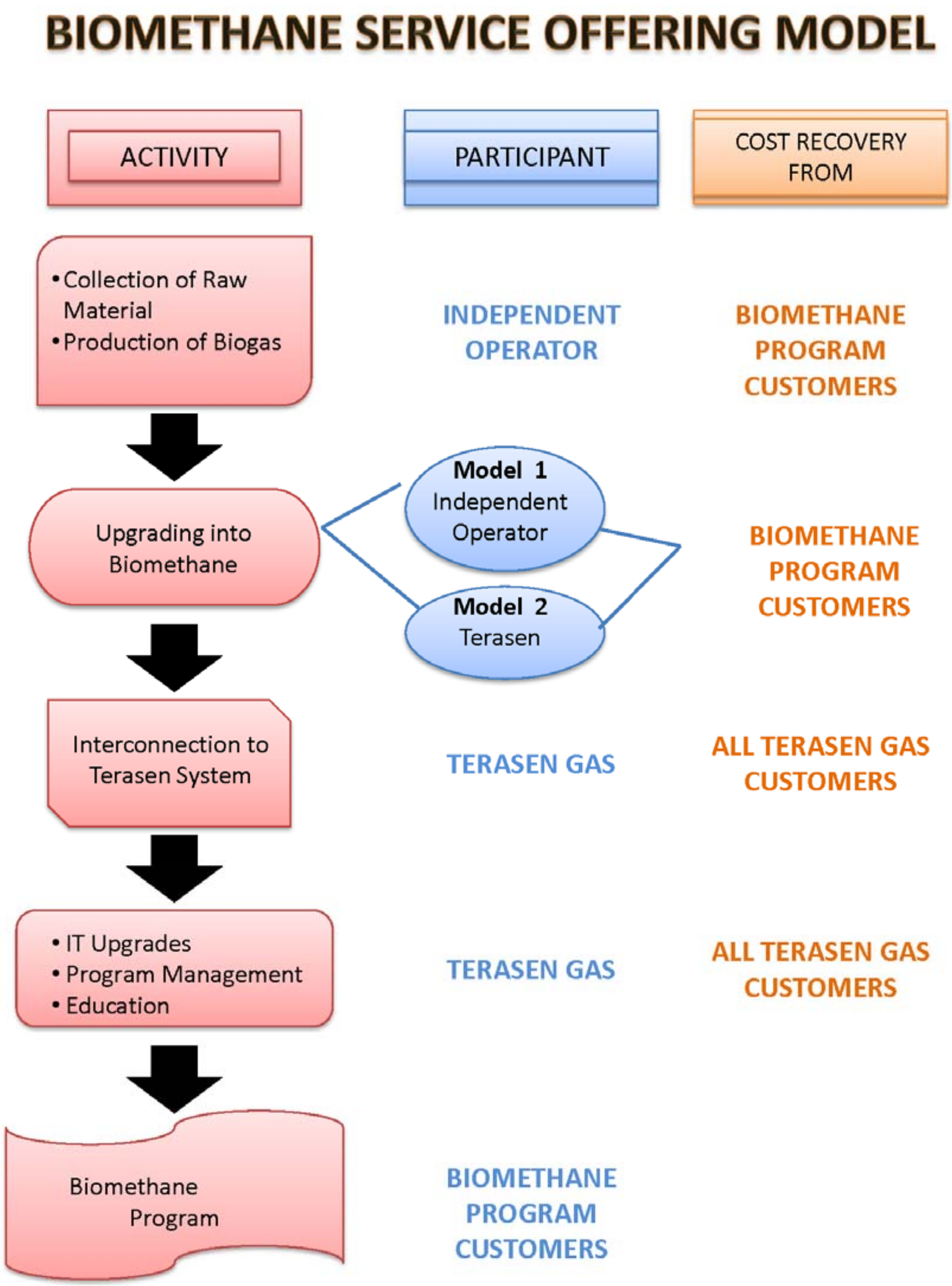
3.1.3 Cost Allocation and Recovery

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 CO_2e reduction

	Minimum Contract Amount	Maximum Contract Amount
Gigajoules ("GJ") of Natural Gas displaced	84,000	180,000
Tonnes of CO_2e per gigajoule	0.050	0.050
Tonnes of CO_2e reduced	4,200	9,000

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 CO_2e reduction

	Expected Contract Amount	Maximum Contract Amount
Gigajoules ("GJ") of Natural Gas displaced	30,000	45,000
Tonnes of CO_2e per gigajoule	0.050	0.050
Tonnes of CO_2e reduced	1,500	2,250

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, perfluorcarbons, 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)

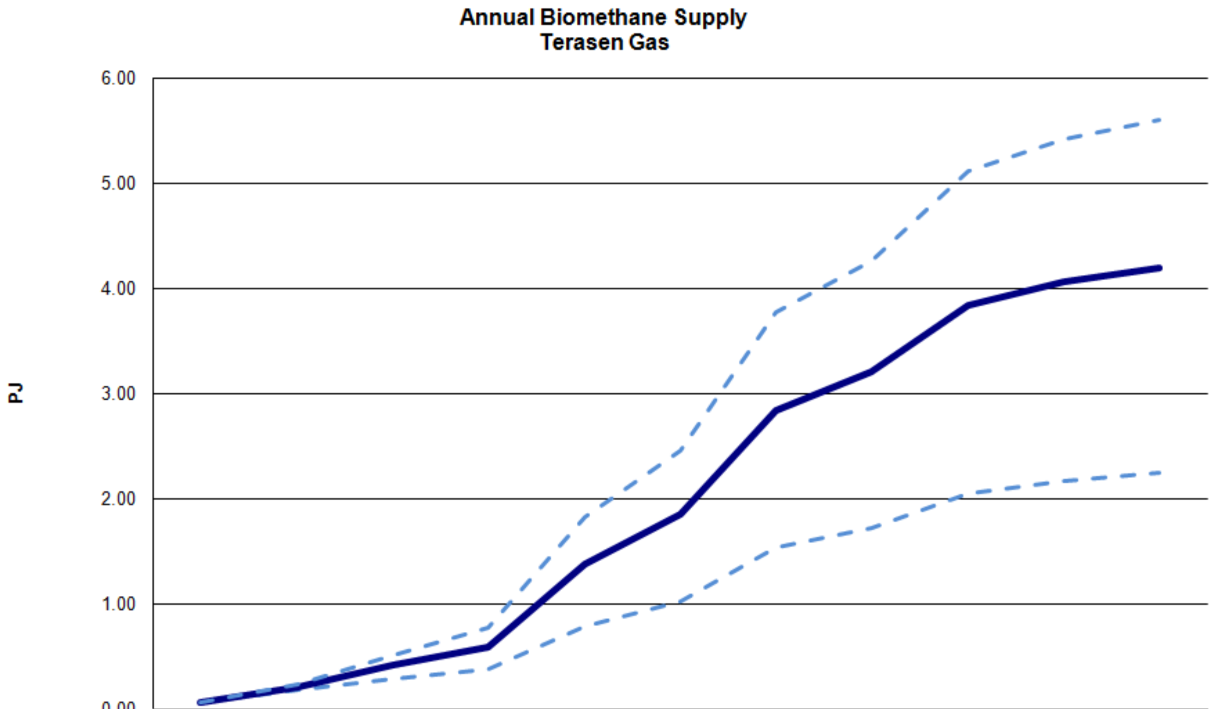
However, Terasen notes that the sources of the energy and estimated supply of Biomethane are not well established. It is Terasen Gas' position that the first four years of the estimate are more accurate than the long-term forecast, but both long-term and short-term estimates are subject to some uncertainty. (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 10^6 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)



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

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 assests 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 acknolwedges 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 maintenace 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	2010	2011	2012 [1]
		($ thousands)		
1	**O&M Costs - All Customers**			
2	Labour Costs - One FTE	25.0	100.0	100.0
3				
4	Computer Costs - Additional Reporting	-	-	10.0
5				
6	Customer Education	160.0	240.0	300.0
7	Internal Reporting Changes	0.8	2.4	-
8	Inbound Calls			6.4
9	Fees & Administrations Costs	160.8	242.4	306.4
10				
11	Inbound Calls	7.2	28.7	-
12	Rate Changes	-	4.0	-
13	Application Support	165.6	-	-
14	Contractor Costs	172.8	32.7	-
15				
16	**Total O&M Costs - All Customers**	**358.6**	**375.1**	**416.4**
17				
18	**O&M Costs - Catalyst Project (3 months in 2010)**			
19	Electrical Power	1.0	2.0	2.0
20	Equipment Maintenance	1.0	2.0	2.0
21	Other	14.5	29.0	29.6
22	Total Catalyst Materials & Supplies	16.5	33.0	33.7
23				
24	**O&M Costs - Salmon Arm Project (6 months in 2010)**			
25	Electrical Power	11.5	46.0	46.9
26	Equipment Maintenance	1.3	5.0	5.1
27	Other	1.3	5.0	5.1
28	Total Salmon Arm Materials & Supplies	14.0	56.0	57.1
29				
30	Total Materials & Supplies	30.5	89.0	90.8
31				
32	**O&M Costs - Biogas Customers (Customer related)**	14.6	82.4	56.9
33				
34	**Total O&M Costs - Biogas Customers**	**45.1**	**171.4**	**147.7**
35				
36	[1] Years subsequent to 2012 are adjusted by inflation			

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

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

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

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

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

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;

…/2

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 Shushwap 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;

…/3

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.

(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.

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
COMMISSION DOCUMENTS	
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

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
INTERVENER DOCUMENTS	
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

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

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

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 *Act* or *UCA*	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,

(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,

(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.

(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.

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-141-09

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

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

and

An Application by Terasen Gas Inc.
for Approval of 2010 and 2011 Revenue Requirements and Delivery Rates

BEFORE: A.W.K. Anderson, Panel Chair/Commissioner
D.A. Cote, Commissioner
M.R. Harle, Commissioner

November 26, 2009

ORDER

WHEREAS:

A. On June 15, 2009 Terasen Gas Inc. ("Terasen Gas") filed an application for approval of interim and permanent delivery rates effective January 1, 2010 and January 1, 2011 (the "Application") pursuant to sections 59 to 61 and 89 of the *Utilities Commission Act* (the "Act"), representing an increase of 5.3 percent for 2010 and 4.1 percent for 2011; and

B. Terasen Gas sought other approvals in the Application, including Orders pursuant to sections 59 to 61 of the Act, approving Tariff changes effective January 1, 2010 for Compression and Refueling and Transportation Services for Natural Gas Vehicles and economic models for evaluating biogas projects and alternative energy extensions for geo-exchange, solar thermal and district energy systems to complement its core natural gas business; and

C. The interim and permanent delivery rates sought in the Application are subject to adjustment for any changes in Terasen Gas' allowed return on equity and capital structure; and

D. Terasen Gas proposed a written hearing process to address the Application but was open to a Negotiated Settlement Process ("NSP") addressing all of the issues; and

E. In accordance with Commission Order G-76-09, a Workshop was held July 6, 2009 for a review of the Application and a first Procedural Conference was held on July 15, 2009. Commission Order G-89-09 established the requirement for a second Procedural Conference, held on September 25, 2009 to address the regulatory process and preliminary timetable; and

F. At the second Procedural Conference, the Commission Panel received submissions on the principal issues arising from or related to the Application, process options for the review of the Application, location of the proceedings and other matters that would assist the Commission's efficient review of the Application. The primary issues raised were whether a separate Certificate of Public Convenience and Necessity ("CPCN") review was required for the Alternative Energy Solutions proposed in the Application and whether the regulatory process should be in the form of an oral or written hearing or NSP; and

G. The Intervenors expressed a wish to avoid a separate CPCN process for the Alternative Energy Solutions and all Intervenors supported an NSP for the review of the Application. The Intervenors submitted that, in the event that the NSP is not successful in resolving all issues, an Oral Public Hearing could be ordered by the Commission. Terasen Gas requested that, if an Oral Public Hearing is established, it be limited in scope; and

H. Terasen Gas proposed that its application for interim rate approval be deferred until the end of November 2009; and

I. By Order G-119-09, the Commission Panel established a regulatory timetable for an NSP commencing October 21, 2009. The settlement discussions concluded on November 3, 2009; and

J. On November 13, 2009, the Negotiated Settlement Agreement ("NSA"), together with the Letters of Support received from the participants in the NSP, the Letter of Comment from Commission Staff and Terasen Gas' response to the Letter of Comment ("Settlement Package"), was made public and circulated to the Commission Panel; and

K. The Settlement Package was also distributed to Registered Intervenors who did not participate in the NSP ("Other Intervenors"). The Other Intervenors were requested to provide their comments on the Settlement Package to the Commission by November 20, 2009. The Commission Panel received no comments from Other Intervenors regarding the Settlement Package; and

L. The Commission Panel having reviewed the proposed NSA and the comments related thereto and noting the support of all parties to the proposed Negotiated Settlement Agreement, in which only sections 12(a) and (b) are severable, subject to the implementation of section 12.2, considers that approval is warranted.

NOW THEREFORE pursuant to sections 59 to 61 and 89 of the Act the Commission orders as follows:

1. The Negotiated Settlement Agreement attached as Appendix A to this Order is approved.

2. TGI is to file an amended Summary of Rates and Bill Comparison schedules based on the Negotiated Settlement Agreement.

3. The Commission will accept, subject to timely filing by TGI, amended permanent Gas Tariff Rate Schedules in accordance with the terms of this Order. TGI is to provide notice of the permanent rates to customers via a bill message, to be reviewed in advance by Commission Staff to confirm compliance with this Order.

DATED at the City of Vancouver, In the Province of British Columbia, this 26th day of November 2009.

BY ORDER

Original signed by:

A.W.K. Anderson
Panel Chair/Commissioner

Attachment

ERICA HAMILTON
COMMISSION SECRETARY
Commission. Secretary@bcuc.com
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Log No. 29797

VIA EMAIL

November 13, 2009

Registered Intervenors
(*TGI-2010-11RR-RI*)

Dear Registered Intervenors:

Re: Terasen Gas Inc.
2010-2011 Revenue Requirements Application
Negotiated Settlement

Enclosed with this letter is the proposed settlement package for Terasen Gas Inc.'s 2010-2011 Revenue Requirements Application.

This settlement package is now public and is being submitted to the Commission and all Intervenors. Also enclosed are Letters of Comment received to date from the participants in the negotiated settlement process.

Prior to consideration by the Commission, Intervenors who did not participate in the settlement negotiations are requested to provide to the Commission with their comments on the settlement package by Friday, November 20, 2009. Thereafter, the Commission will consider the settlement package. A public hearing may not be required unless there is significant opposition to the proposed settlement.

Yours truly,

Y. Lapierre
for: Erica M. Hamilton

PWN/yl
Attachments
cc: Mr. Tom Loski
Chief Regulatory Officer
Terasen Gas Inc.
(Via Email: *regulatory.affairs@terasengas.com*)

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS INC.
DATED THURSDAY, NOVEMBER 5

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

and

An Application by Terasen Gas Inc.
for Approval of 2010 and 2011 Revenue Requirements and Delivery Rates
Negotiated Settlement Process

WHEREAS:

A. On June 15, 2009, Terasen Gas Inc. ("TGI") filed its 2010 and 2011 Revenue Requirements Application, which was supplemented by a filing on July 9, 2009 and amended by filings on August 14 and September 18, 2009 (the "Application"); and

B. Amongst other things, the Application sought:

1. An order pursuant to sections 59 to 61 of the *Utilities Commission Act* (the "Act"), approving delivery rates for all non-bypass customers effective January 1, 2010 and January 1, 2011, representing an increase of 5.3 percent for 2010 and an additional 4.1 percent for 2011, subject to changes in TGI's allowed return on equity ("ROE") and capital structure; and

2. An order pursuant to section 44.2 of the Act approving an expenditure schedule for the continuation in 2011 of TGI's residential and commercial Energy Efficiency and Conservation ("EEC") funding, as well as new EEC funding for 2010 and 2011 for interruptible industrial programs and innovative technologies; and

3. New tariff offerings and economic tests for Compression and Refuelling and Transportation Services for Natural Gas Vehicles ("NGV"), geo-exchange, solar thermal and district energy systems and a pilot program for Biogas; and

C. A complete listing of the relief sought by TGI in the Application was included in Section D (pages 513-516)[1] of the Application; and

D. In accordance with Commission Order No. G-76-09 issued on June 19, 2009, a Workshop was held on July 6, 2009 for a review of the Application, a procedural conference was held on July 15, 2009, and TGI responded to two rounds of Information Requests; and

E. In accordance with Commission Order No. G-89-09 issued on July 20, 2009, a second procedural conference was held on September 25, 2009; and

---

1 Page 516 of the Application was amended on September 18, 2009.

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS INC.
DATED THURSDAY, NOVEMBER 5

F. On October 2, 2009, the Commission issued Order G-119-09 establishing a Negotiated Settlement Process ("NSP") for the Application; and

G. The Parties to the NSP were TGI, British Columbia Old Age Pensioners et al. ("BCOAPO"), Commercial Energy Consumers Association of British Columbia ("CEC"), Teck Coal Ltd. ("Teck"), and the Ministry of Energy, Mines and Petroleum Resources ("MEMPR") (collectively referred to in this Agreement as the "Parties"); and

H. At the outset of the NSP on October 21, 2009, Commission Staff provided the Parties with a document prepared by the Commission Panel titled "Issues of Particular Concern to the Commission Panel", a copy of which is appended as Appendix 1 to this Agreement; and

I. The NSP was held on October 21-23, 30, and November 3 and 4, 2009; and

J. The Parties have negotiated in good faith to achieve a compromise settlement, reflected in this Agreement, of the issues raised by the Application, and the Commission Panel document referenced in recital H above, and further consider the Agreement reached to be fair, just and reasonable; and

K. This Agreement consists of four Parts:

Part I includes general provisions;

Part II includes the items agreed to that differ from what was requested in the Application;

Part III includes the items agreed to that remain as proposed by TGI in the Application; and

Part IV includes revised financial schedules reflecting all items set out in the Agreement.

NOW THEREFORE THE PARTIES AGREE AS FOLLOWS

PART I – GENERAL

1. **<u>Agreement a Product of Compromise</u>**

The Parties recognize and emphasize that this Agreement is the product of compromise on the part of all Parties, yielding an overall package that the Parties consider to be fair, just and reasonable. The Parties agree that any compromises resulting from this Agreement are without prejudice to the Parties' ability to take different positions after 2011 and without prejudice to the Parties right to intervene in any applications contemplated in or resulting from this Agreement.

2. **Whole Agreement**

Unless otherwise stated in this Agreement, portions of this Agreement cannot be removed or changed by the Commission without nullifying the whole Agreement.

3. **TGI to Manage Business**

The Parties agree that TGI will have the discretion to manage its business and determine how best to allocate the overall O&M and Capital expenditures stipulated in this Agreement.

4. **Final IFRS Rate-regulated Activity Standard**

The Parties acknowledge that this Agreement is predicated on the Final IFRS Rate-regulated Activity Standard permitting the financial accounting treatment contemplated in this Agreement in the manner outlined in the current Exposure Draft on Rate-regulated Activities. The Parties agree that if, in TGI's opinion, the Final IFRS Rate-regulated Activity Standard differs from the current Exposure Draft on Rate-regulated Activities so as not to permit the financial accounting treatment contemplated in this Negotiated Settlement Agreement, which among other things anticipates the recognition of regulatory assets and liabilities for external reporting purposes, then TGI is at liberty to apply to the Commission during the period of this Agreement for a determination of that issue, and to seek changes in the regulatory treatment contemplated in this Agreement to accord with the Final IFRS Rate-regulated Activity Standard, with the resulting impacts flowed through into rates commencing in 2011.

PART II – AGREED CHANGES FROM THE APPLICATION

5. **Delivery Rates**

The Delivery rate changes for 2010 and 2011 that would flow from this Agreement would be a decrease of 1.73 per cent in 2010 and an increase of 3.93 per cent in 2011, subject to being updated as contemplated in this Agreement. Issue No. 5 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "2010 Rate Changes – in the event that a 2010 rate reduction were to occur as a result of negotiations, the current rates should remain unchanged and place the revenue surplus into a deferral account to apply against 2011 and future rate increases with a phase in amortization that strives for rate stability."

Therefore, the Parties agree that this Agreement will not result in a decrease in delivery rates for 2010 and that the 2010 forecast revenue surplus will be recorded in a 2010 Revenue Surplus Deferral Account and be applied to offset any forecast increase in delivery rates in 2011. The forecast 2010 revenue surplus of $9.2 million per Schedule 1 included in Part IV of this Agreement, is recorded in the 2010 Revenue Surplus Deferral Account, which will be amortized in 2011 to reduce the 2011 forecast revenue deficit. The 2010 Revenue Surplus Deferral Account will be included in Rate Base.

However, the delivery rates for 2010 and 2011 will be updated to reflect changes in TGI's allowed ROE and capital structure flowing from the Commission's decision in TGI's concurrent ROE and Capital Structure Application[2], or as adjusted from time to time by the Commission. Nothing in this Agreement precludes TGI from applying to the Commission in 2010 or 2011 for changes to its allowed ROE and capital structure.

6. **Service Quality Indicators**

The Parties agree that TGI will report on the same SQI's as set out in the 2004-2007 PBR Agreement and the 2008-2009 extension thereof through quarterly postings on TGI's website.

7. **Customer Additions Forecast**

The Parties agree that TGI's net Residential customer additions forecast is revised to be 5,952 in 2010 (increase of 352 from Application[3]) and 6,166 in 2011 (increase of 316 customers from the number specified in the Application), reflecting the updated published CMHC Q3 2009 forecast, and TGI's year end 2009 number of customers has additionally been updated to be 835,862. Customer additions for the other rate classes remain unchanged from what was specified in the Application[4].

8. **Use Per Customer Rates**

The Parties agree that the Residential annual use per customer is revised upward from 89.7 GJ to 91.7 in 2010 and from 88.3 to 90.3 in 2011. Use per customer rates for the other rate classes remain unchanged from what was included in the Application (other than Industrial as set out in item 9).

9. **Industrial Demand Forecast**

The Parties agree that the industrial demand forecast is revised upwards from what was requested in the Application based on responses TGI has since received from the 2009 Industrial Survey and actual year-to-date demand. The revised industrial demand forecast includes forecast demand of 46.5 PJ and 46.5 PJ (compared to 43.4 PJ and 43.3 PJ as presented in the Application) for 2010 and 2011 respectively.

---

[2] Filed jointly by the Terasen Utilities [TGI, Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.] on May 15, 2009.

[3] See Application, page 276

[4] IBID

~~CONFIDENTIAL~~

NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS INC.
DATED THURSDAY, NOVEMBER 5

10. Inclusion of SCP Capacity in MCRA

The Parties agree that TGI will continue for 2010 and 2011 to include in the MCRA the $3.6 million representing the annual cost of Southern Crossing Pipeline (SCP) capacity, because the benefits and use of the SCP capacity are used by Core Market Customers (Rate Schedules 1-7).

11. Energy Efficiency and Conservation ("EEC") Funding for 2010

The Parties agree as follows in respect of the EEC funding sought by TGI for 2010:

(a) TGI will reallocate from residential and commercial EEC programs an additional $1.6 million from the amount approved for 2010 in the EEC Decision[5] to low income and rental housing programs. This brings the total for low income and rental housing programs to $2.4 million for 2010.

(b) EEC funding for industrial interruptible programs for 2010 will be $435,000, which is the amount requested by TGI in the Application.

(c) EEC funding for innovative technologies will be $2.3 million for 2010, which is the amount requested by TGI in the Application.

(d) All agreed to EEC expenditures will be considered and evaluated within the existing portfolio, and be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 514, Item 6). However, Innovative Technology programs will be managed by TGI as a separate segment of the overall portfolio to have a weighted average Total Resource Cost ("TRC") of 1.0 or more. TGI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.

12. EEC Funding for 2011

12.1 The Parties agree as follows in respect of the EEC funding sought by TGI for 2011:

(a) EEC funding for residential and commercial programs for 2011 will be $23.075 million, which is the amount requested by TGI in the Application.

(b) TGI will reallocate from 2011 residential and commercial EEC funding ($23.075M for 2011) an additional $1.6 million (from the $0.8 million included in the Application) to low income and rental housing programs. This brings the total for low income and rental housing programs to $2.4 million for 2011.

---

5 Decision and Order No. G-36-09 dated April 16, 2009 in the TGI-TGVI Energy Efficiency and Conservation Application

(c) EEC funding for industrial interruptible programs will be $1.875 million for 2011, which is the amount requested by TGI in the Application.

(d) EEC funding for innovative technologies will be $4.669 million for 2011, which is the amount requested by TGI in the Application.

(e) All agreed to EEC expenditures will be considered and evaluated within the existing EEC portfolio, and will be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 514, Item 6). However, Innovative Technology programs will be managed by TGI as a separate segment of the overall portfolio to have a weighted average TRC of 1.0 or more. TGI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.

(f) TGI will report to the Commission on industrial interruptible and innovative technology programs as part of TGI's annual report on EEC activities required under the EEC Decision.

The Parties offer the following rationale for the agreed upon 2011 EEC funding.

All Parties agree that it is important to maintain EEC funding levels in 2011 to allow customers to have continued access to EEC programs and incentives. The residential and commercial EEC programs relating to the $23.075 million funding in 2011 on a portfolio basis in aggregate have a TRC of one or more. This means that, from a resource perspective and on a portfolio basis, these programs are expected to yield favourable results for customers. The predictability and continuity of these programs on a sustained basis is critical to their overall success.

Issue No. 1 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "EEC Program – TGI is to provide results of programs approved by the EEC Decision and expectations for new programs before the Commission Panel will approve additional EEC program funding."

There are practical difficulties associated with the approach identified by the Commission Panel. They include the following:

- As per the EEC Decision (Order No. G-36-09), TGI will be reporting 2009 activities and results by no later than March 31, 2010. This report will also outline the forecasted activities and programs for 2010. Recognizing the timing of the recent EEC Decision and its current implementation in the Fall of 2009, the EEC Report for 2009 results will give the Commission and stakeholders another check point to validate the level of spend for 2011. However, there is expected to be very little additional information on the results of programs available in March 2010 than exists presently and is included in the evidentiary record of this proceeding. TGI's

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS INC.
DATED THURSDAY, NOVEMBER 5

EEC programs only completed start up phase in the Fall of 2009. It typically takes longer than 6-8 months to achieve momentum with EEC programs. There will be no information available in March 2010 on results for industrial programs or programs relating to innovative technologies initiated in 2010 as a result of this Agreement. The information that the Commission Panel appears to desire will be more likely included in TGI's 2010 results report to be filed in March 2011.

- Employees responsible for the programs at TGI, whose salaries are funded from EEC funding, will face the prospect of losing their jobs in 2011. This could lead to employee retention issues. Employee turnover issues may disrupt the program implementation progress and potentially be more costly if EEC activity is ceased and later resumed.

- Programs will need to begin winding down in advance of 2011 if the 2011 funding is not approved. For example, programs will need to have an end date of December 31, 2010 which may not yield positive results since programs will be winding up in the middle of the heating season.

12.2 The Parties agree that the Commission may sever Section 12.1 (a) and (b) above from this Agreement, with the remainder of this Agreement remaining in force and effect. If the Commission severs Section 12.1 (a) and (b), then the Parties agree that the following provisions take effect:

(a) The Residential and Commercial EEC programs totaling $23.075 million in 2011 will be removed from the EEC expenditure forecast and the revenue requirements for 2011. (If 12.2 takes effect, the financial schedules in Part IV of this Agreement and the revenue requirements resulting from this Agreement will be revised to reflect this).

(b) The Parties agree that the first annual report on EEC Activities, which was due to be filed on March 31, 2010 pursuant to Order No. G-36-09, can be filed on or before June 30, 2010. Concurrent with that report, TGI will file an application with the anticipation of a decision within 120 days after filing. The application will include requests for:

i. approval of the above EEC funding for 2011;

ii. approval of the same financial treatment approved in the EEC Decision; and

iii. approval for the continuation of the portfolio approach and assessment methodology as approved in the EEC Decision.

13. Alternative Energy Solutions

Alternative Energy Solutions ("AES") means Geo-exchange, Solar-thermal and District Energy Systems as those terms are described in the Application.

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS INC.
DATED THURSDAY, NOVEMBER 5

Natural Gas service taken in combination with AES will be charged under TGI's natural gas rates.

The Parties agree that the costs incurred by TGI to provide AES should not be recovered as part of natural gas service rates, and visa versa. The Parties agree that TGI's proposed New Energy Solutions Deferral Account, attracting AFUDC, is an appropriate mechanism to address allocation issues as between TGI's gas customers and TGI's AES customers. Therefore, the Parties agree that the new Energy Solutions Deferral Account will remain in effect pending a future rate design application at an unspecified future date after 2011 and will capture and record the following (plus AFUDC) to be recovered from AES customers:

(a) Direct costs associated with AES projects as outlined on pages 267-268 of the Application, including cost of design, equipment, etc. constructing and financing; and

(b) Sales and marketing O&M and other development costs will be directly charged to the deferral account by time sheets or other direct charge (estimated at $1.0 million in 2010 and $1.5 million in 2011, representing a portion of the agreed upon Gross O&M reduction from gas customers of $4.0 million in 2010 and $5.5 million in 2011); and

(c) An appropriate overhead allocation, which the parties have agreed will be $500,000 in each of 2010 and 2011 (representing a portion of the agreed upon Gross O&M reduction from gas customers of $4.0 million in 2010 and $5.5 million in 2011).

Revenues received from customers for all AES projects, which are based on contracts approved by Commission will be recorded in the AES deferral account.

The risk of non-recovery of amounts in the New Energy Solutions Deferral Account will not be borne by natural gas ratepayers. The Parties agree that any debit balance in the New Energy Solutions Deferral Account will not be recovered through natural gas rates and any credit balance will not be applied to reduce natural gas rates.

In evaluating AES projects, TGI will apply the economic test outlined in the Application. The Parties agree that the proposed GT&C (Section 12A – Alternative Energy Extensions) are acceptable. Pursuant to the *Utilities Commission Act,* within the Alternative Energy class of service, project-specific contracts with AES customers will be filed with the Commission for acceptance as a rate, at which time the Commission may review and adjust the economic test and GT&C Section 12A – Alternative Energy Extensions.

The CPCN threshold of $5 million applies to AES projects brought forward in 2010 and 2011.

The Parties agree that it is premature to address issues relating to the gas load and gas consumption profiles of AES projects that incorporate a natural gas component. Such issues are appropriately addressed in a future rate design application, once TGI has sufficient AES customers that take gas so as to provide reliable information on gas load and gas consumption profiles.

TGI will capture costs and revenue on a project specific basis and will report on AES projects as part of the next Revenue Requirements application.

14. Natural Gas for Vehicles (“NGV”)

The Commission Issue No. 2 in the Commission Panel’s “Issues of Particular Concern to the Commission Panel” stated:

> “Natural Gas Vehicles (“NGV”) – if NGV is to proceed why should the natural gas ratepayer fund this initiative rather than Terasen’s non-regulated businesses or the competitive market?”

The Parties agree:

(a) NGV Rate Schedule 26 - NGV Transportation Service should be approved as filed.

(b) The marketing costs in support of NGV that are included in the revenue requirements Application are appropriately recoverable in 2010 and 2011 rates.

(c) Upon acceptance of this Agreement by the Commission, TGI withdraws its request in this Application for the following:

  i. Rate Schedule 6C NGV Compression and Refueling Service and 6A NGV Refueling Service; and

  ii. the Compression Service (“CS”) Test; and

  iii. NGV non-rate base deferral account.

The Parties acknowledge that these requests are being withdrawn by TGI to facilitate a settlement on other issues presented in this Application. The Parties agree that TGI’s withdrawal of its requests regarding NGV is without prejudice to TGI’s right to bring forward similar requests in 2010 or 2011 or otherwise in the future. The Parties acknowledge that TGI intends to develop this area of business and that TGI anticipates it will bring forward applications on NGV projects to the Commission on a case-by-case basis during the term of this Agreement and in future years. The Parties agree that TGI is at liberty to do so.

15. Biogas

Issue No. 3 in the Commission Panel’s “Issues of Particular Concern to the Commission Panel” stated:

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

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS INC.
DATED THURSDAY, NOVEMBER 5

The Parties agree that, upon acceptance of this Agreement by the Commission, TGI withdraws its requests in this Application related to Biogas. The Parties acknowledge that these requests are being withdrawn to facilitate a settlement on other issues presented in this Application. The Parties agree that TGI will bring forward an application (the "Biogas Application") during the test period that will:

(a) Address the economic assessment model; and

(b) Provide Biogas rates (including green rate, transportation rate, etc.); and

(c) Provide for recovery of costs associated with providing Biogas service.

TGI may include in the Biogas Application any Biogas Projects under development at that time. TGI is, however, not precluded from applying for Commission approval in respect of individual Biogas Projects at any time, either prior to the Biogas Application or afterwards.

16. <u>CPCN Threshold</u>

Issue No. 6 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "CPCN threshold – stay at $5 million."

The Parties accordingly agree that the CPCN threshold will remain at $5 million for 2010 and 2011. TGI's Category B Capital Expenditures forecast for the forecast period will be revised to reflect this change (please see item 18 below).

17. <u>Category A Capital</u>

The Parties agree that Category A Capital will be $43.3 million for 2010 and $46.0 million for 2011, reflecting the proposed amount updated to reflect the published CMHC Q3 2009 forecast, and TGI's adjusted re-forecasted year end net customer addition numbers (as set out in item 7).

18. <u>Category B and Category C Capital</u>

As a consequence of the CPCN threshold being established at $5 million for 2010 and 2011 (see item 16 above), TGI will file CPCN applications for the Huntingdon and Kootenay Crossing projects identified in TGI's Application. The Category B Capital will consequently be reduced by $2.2 million in 2010 and $16.0 million in 2011. TGI will seek deferral treatment for 2011 of the capital costs associated with those projects at the time of filing the CPCN Applications.

The Parties agree that Category B and C Capital will be reduced by a total of $3 million in each of 2010 and 2011. For the purposes of the determination of revenue requirements with this Application, Category B Capital has been reduced by $1 million and Category C IT Capital has been reduced by $2 million.

The revised Category B Capital Expenditures, reflecting both the CPCN adjustment and the $1 million reduction in spending, are now $17.4 million in 2010 and $14.9 million in 2011.

The revised Category C Capital Expenditures, reflecting the $2 million IT Capital reduction, are now $32.8 million in 2010 and $32.7 million in 2011.

19. Gross O&M (to be recovered from gas customers)

The Parties agree that the proposed gross O&M, before shared service allocations, recoverable from gas customers for 2010 and 2011 is reduced from the amounts included in the original Application by $4.0 million in 2010 and a further $1.5 million (for a total impact of $5.5 million) in 2011. This reduction of Gross O&M will result in a reduction in the pool of costs subject to the Shared Services Agreement with TGVI and with TGW by an estimated $3.3 million in 2010 and $4.8 million in 2011. Therefore, and as discussed in Item 21, the final Gross O&M to be included in TGI's cost of service for 2010 and 2011 will be determined based on the Shared Services and Corporate Services allocations determined in the TGVI RRA.

20. Interest Expense

The Parties agree that TGI will update its assumptions around both the issuance of long-term debt and the associated interest rates. TGI has determined that Long-term Debt Series 25 will not be issued December 1, 2009 as originally forecast and is now anticipated to be issued April 1, 2010. In addition, the interest rate forecast for Long-term Debt Series 26, to be issued July 1, 2011, has been revised downwards from 6.13 per cent to 5.65 per cent.

21. Shared Services/Corporate Services Allocations

The 2010 and 2011 revenue requirements stipulated in this Agreement are based on TGI's proposed Shared Services and Corporate Services allocation for 2010 and 2011. The Parties acknowledge, however, that the final amount allocated to TGI for Shared Service and Corporate Services cannot be confirmed until the Commission determines the TGVI RRA. The Parties agree that if the amounts allocated to TGVI for Shared Services and/or Corporate Services for 2010 or 2011 changes from that agreed to in this Agreement as a result of a settlement or decision in the concurrent TGVI RRA proceeding, then the amount(s) allocated to TGI and its revenue requirements for 2010 and 2011 will be updated by a corresponding amount to ensure recovery of all of the combined Corporate Services and Shared Services costs.

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS INC.
DATED THURSDAY, NOVEMBER 5

22. Depreciation Study

The Parties agree that the depreciation rates specified in the Gannett Fleming study included the Application under Appendix H-2 for Parts I-III, and in the Supplemental filing dated July 8, 2009 for Parts IV and V, will be implemented effective January 1, 2010, with the exception of:

(a) Masonry Structures, which has been updated to 40 years instead of 22.88 years; and

(b) the component of those rates that represent recovery of negative salvage (see item 23 below).

Adjusting for the Masonry Structures, negative salvage, and the impacts of capitalized overhead and capital additions changes yields total depreciation expense of $98.3 million in 2010 and $100.5 million in 2011, of which approximately $6.3 million results from the updated Gannett Fleming depreciation study.

The Parties agree that TGI will undertake an updated depreciation study to be included as part of TGI's next Revenue Requirements Application. This study will address the methodology and rates for net negative salvage to be included in cost of service for future periods. TGI will work with Commission staff and a depreciation rate specialist in determining the requirements of the study.

23. Negative Salvage Values

On an annual basis, TGI includes a provision for estimated net negative salvage value (removal costs less proceeds) in its depreciation rates. This treatment recognizes that net negative salvage value is a cost of providing service using the asset and should be recovered from customers over the useful life of the asset. An alternative treatment is to recover the net negative salvage values at the time they are incurred resulting in future customers paying for the removal costs, which TGI views as inappropriate. The inclusion of a provision for estimated net negative salvage value in depreciation rates is a practice that has been followed by TGI historically, and with this RRA TGI had proposed continuation of this treatment. This treatment is consistent with the BCUC Uniform System of Accounts and is generally followed by other investor-owned utilities in British Columbia and across Canada.

The Parties agree that for the purposes of the two year period covered by this Agreement, the provision for net negative salvage (net removal costs) will be removed from the depreciation estimates. Instead, an estimate of the amount of net removal costs to be incurred in each of the years 2010 and 2011 ($8.038 million and $11.29 million) will be included in the cost of service and recovered from customers in each of those years. Any variances between the actual amount of net removal costs realized and the estimated amounts included in cost of service will be recorded in a new deferral account created for this purpose that will be called the "Removal Cost Deferral Account". The amount accumulated in the Removal Cost Deferral Account over the two year period of this Agreement will be recovered from (or returned to) customers in 2012.

TGI continues to be of the position that removal costs should be recovered over the service life of the asset and not at the time the removal costs are actually incurred. TGI will work with Commission staff and a depreciation rate specialist in determining both the methodology and estimates for the removal costs and include the documentation to support the rates in its next depreciation study filed as part of its next Revenue Requirement Application.

24. Unrecovered Losses

Issue No. 7 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "Unrealized losses in rate base – should some of these losses be to the shareholder? Parties should present a separate settlement package."

Unrealized (unrecovered) losses relate to Unrecovered Depreciation on assets used 100 per cent for the provision of utility service to ratepayers (as discussed in the response to BCUC IR 2.131.1.4).

The Parties agree that the treatment for unrecovered losses as proposed in the Application is acceptable for the 2010 and 2011 period covered by this agreement. TGI will work with Commission staff and a depreciation rate specialist in determining both the methodology and estimates for the unrecovered losses and include the documentation to support the rates in its next depreciation study filed as part of its next Revenue Requirement Application.

25. Changes to CCA Rates

TGI amended its 2007 and 2008 tax returns to reflect changes to CCA rates announced in 2007 but not enacted until 2009. TGI proposed this benefit be shared in accordance with the terms of the PBR settlement. Some Parties have expressed the view, however, that all of the benefit should have been flowed through to customers via the Tax Deferral Account. The Parties, acting in good faith, have concluded that they have a fundamental and legitimate disagreement regarding the terms of the 2004-2009 PBR Settlement Agreement as it relates to the items to be included in the Tax Deferral Account. TGI has nevertheless agreed, as a compromise in furtherance of reaching an overall Agreement among the Parties, to include the full value of the incremental tax benefit associated with the difference in the CCA rates for 2007 and 2008 totalling $921,000 and remove the proposed 50% sharing benefit from the Earnings Sharing Mechanism.

26. Taxes – Tax Benefits Relating to Prior Periods – SCP Landscaping Costs

TGI had proposed to accelerate the deduction of the remaining Regulatory Tax balance of SCP Landscaping costs (amounting to approximately $8.2 million) in 2009. That proposal would have resulted in the related tax benefit of approximately $2.4 million being flowed through the Earnings Sharing Mechanism pursuant to the PBR Settlement Agreement, resulting in a net benefit to customers of approximately $1.2 million.

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS INC.
DATED THURSDAY, NOVEMBER 5

The Parties agree that, instead, TGI will continue to amortize the balance of SCP Landscaping costs for 2009 as contemplated in the approved rates for 2009 and consistent with prior years, resulting in a deduction of approximately $0.3 million for Regulatory Tax purpose in 2009 and a related tax benefit. TGI will then deduct the remaining balance (approximately $7.9 million) in 2010 with the full value of the remaining benefit (approximately $2.3 million) going to customers reflected as a reduction in revenue requirements in 2010.

The Parties agree that the acceleration of this benefit to customers was the result of tax planning actions taken by TGI and acknowledge that the agreed upon treatment set out above reflects customers receiving 100% of the value of the deductions of the SCP Landscaping costs. The intervenor Parties to this Agreement will not seek any additional recovery in respect of SCP Landscaping costs.

27. Overheads Capitalized

The Parties agree to a change in the overheads capitalized rate to 14 per cent of Gross O&M for 2010 and 2011 which reflects the approximate actual Overheads Capitalized rate for 2009.

28. International Financial Reporting Standards ("IFRS") 2010 Impact

Issue No. 4 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "International Financial Reporting Standards ("IFRS") – no IFRS impact in 2010."

The Parties agree to defer the 2010 revenue requirement impact of IFRS to be recovered in rates in 2011 (relating specifically to capitalization of the current service portion of pension and OPEB related costs; capitalization of inspection costs; and timing of depreciation expense) up to a maximum of $1.0 million. Amounts, if any, over $1.0 million would be deferred and recovered in rates after 2011 based on the amortization approved by the Commission at that time.

PART III – REQUESTS UNCHANGED FROM THE APPLICATION

The Parties agree to the following items set out in this section, which are consistent with the proposals in TGI's Application.

29. Rate Proposals as per Application Part III, Section D .1 - Approvals Sought

The Parties agree to the following rate proposals, as set out in TGI's Application:

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS INC.
DATED THURSDAY, NOVEMBER 5

(a) Allocation of delivery margin rate changes - Annual margin increase allocated to variable (volumetric & demand) based delivery charges, with no change to fixed (basic and admin fee) charges in each year (Application Page 513, Item 1).

(b) Earnings Sharing Mechanism (ESM) rider (incl. end of term capital) - Change the ESM rate rider to be ($0.040)/GJ effective January 1st, 2010, and change the estimated ESM rate rider to be ($0.046)/GJ effective January 1st. 2011. ESM amount to include End of Term Capital phase out and to be amortized over two years. The final 2011 rider amount will be adjusted based on 2009 actual earnings. TGI will submit an application to change the 2011 ESM rate rider at the same time it submits its Q4 quarterly gas cost report in early December 2010 (Application Page 513, Item 3).

(c) Rate Stabilization Adjustment Mechanism (RSAM) rider - Change the RSAM rate rider to be ($0.053)/GJ effective January 1st, 2010 and change the estimated RSAM rate rider to be ($0.052)/GJ effective January 1st, 2011. The 2011 rider amount will be adjusted based on 2009 actual results and 2010 year to date actual results. TGI will submit an application to change the 2011 RSAM rate rider at the same time it submits its Q4 quarterly gas cost report in early December 2010 (Application - Page 514 Item 4).

30. <u>Accounting Policy Changes as per Application Part III, Section D.1 - Approvals Sought - to be effective January 1, 2010</u>

The Parties agree to the following accounting policy changes, as set out in TGI's Application:

(a) Training and Feasibility Study Costs to be treated as O&M expense, rather than capital (Application Page 515 and 516, Item 11).

(b) Capitalization of Major Inspection Costs, including the creation of a new Asset Class (Application Page 515 and 516, Item 11).

(c) Capitalization of the Current Service portion of Pensions and OPEBs expense that is applicable to capital projects (Application Page 515 and 516, Item 11).

(d) Capitalization of Deprecation on Assets used in Construction (Application Page 515 and 516, Item 11).

(e) All capital expenditures, including CPCNs, to be included in plant in service (and rate base) in the month following the available-for-use date, with depreciation starting at that time (Application Page 515 and 516, Item 11).

(f) Treatment of Vehicle Lease as a capital lease and inclusion of the NBV of vehicles in rate base (Application Page 515 and 516, Item 11).

(g) Discontinuation the Software Tax Credit as part of the CIAC additions (Application Page 515 and 516, Item 11).

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS INC.
DATED THURSDAY, NOVEMBER 5

31. Various Accounting Related Proposals as per Application Part III, Section D .1 - Approvals Sought effective January 1, 2010

The Parties agree to the following accounting related changes, as set out in TGI's Application:

(a) Adoption of the Cash Working Capital Lead/Lag Days as set out in the Lead/Lag study (Application page 515, Item 8c).

(b) Consolidated Core Market Administration Expenses (for TGI, TGVI and TGW), including allocation percentages to TGVI and TGW (Application page 515, Item 8d).

(c) Modify the Pricing Methodology for Company Use Gas to be based on market-based Sumas pricing, rather than pricing for expired "netback" contracts (Application page 514, Item 7a).

(d) The MCRA will absorb any volumes not used or excess volumes required for company use gas, as opposed to the O&M costs being adjusted for the differences (Application page 514, Item 7b).

32. Tariff Change Proposals as per Application Part III, Section D .1 - Approvals Sought, Item 12 & 13

The Parties agree to the following Tariff changes, as set out in TGI's Application:

(a) New NGV Transportation Service (RS 26)

(b) Revised Fee New Customer Application fee from $85 to $25

(c) Revised Fee Meter Testing fee from $30 to $60

33. Deferral Account Proposals as per Application Part III, Section D .1 - Approvals Sought, Item 10

The Parties agree to the continuation, modification or adoption of the following deferral accounts as set out in TGI's Application:

(a) Deferral Accounts - No Change:

i. CCRA, MCRA, RSAM, and associated Interest and Revelstoke Propane (Application pages 429 and 430, Items (1) (a), (1) (b), (1) (c), (1) (d), (1) (e)).

ii. NGV Conversion Grants (Application page 432, Item (2) (b)).

iii. Property Tax variance (Application page 433, Item (3) (a)).

iv. Insurance variance (Application page 433, Item (3) (b)).

v. BCUC Levies variance (Application page 433, Item (3) (d)).

vi. Interest variance (Application page 434, Item (3) (e)).

vii. Olympic Security costs (Application page 434, Item (3) (g)).

viii. IFRS conversion costs (Application page 435, Item (3) (h)).

ix. Accounts Amortized in 2010 (Application page 438, Item (6) (a)).

x. SCP PST Reassessment (Application page 439, Item (6) (b)).

xi. Deferred Service Line Installation Fee (Application page 439, Item (6) (d)).

xii. ESM (Application page 440, Item (6) (e)).

(b) Deferral Accounts - Modified:

i. SCP Mitigation Revenues Variance Account - combine the two currently approved accounts into one account (Application page 431, Item (1) (f)).

ii. Pension & OPEB variance - modify to add OPEB (Application page 433, Item (3) (c)).

iii. Tax variance - broader (changes in tax laws, practices, reassessments) (Application page 434, Item (3) (f)).

iv. Pension and OPEB funding Differences - expand to include pension funding differences and include addition in rate base not net of tax (Application page 437, Item (5) (c)).

(c) Deferral Accounts - New:

i. Interest variance calculation on gas in storage inventory (Application page 434, Item (3) (e)).

ii. Costs of applications (CCE, ROE, RRA) (Application page 435, Item (4)).

iii. IFRS Transitional Deferral Account (Application page 435, Item (5) (a)).

iv. Gains and Losses on Asset Disposition (Application page 436, Item (5) (b)).

v. CCE CPCN Costs (incremental non-capital costs plus timing impacts) (Application page 437, Item (5) (d)).

vi. LILO Reassessment (Application page 439, Item (6) (c)).

34. Transfer Pricing Policy (TPP) and Code of Conduct (COC)

The Parties agree that the existing COC and TPP Policies will be maintained.

PART IV – REVISED FINANCIAL SCHEDULES

The revised Financial Schedules follow.

13. Financial Schedules

Summary of TGI 2010 and 2011 Revenue Requirement Increase

Nov 5, 2009 NSP Agreement

		2010 ($ Millions)		Incremental 2011 ($ Millions)	Cumulative 2011 ($ Millions)	
Rebase from Formula Capital and O&M						
Rate Base- Net Plant in Service						
Equity Finance Expense	$ (2.0)		$ -			
Debt Finance Expense	(3.0)		-			
Utility O&M	(8.0)		-			
Overheads Capitalized	1.3					
After Tax Depreciation	(10.0)		-			
Tax Impacts of Rebase Depreciation	(4.3)		-			
Other Revenue	2.6		-			
Taxes	1.0	$ (22.4)	-	$ -	$ (22.4)	
Volumes/Revenue Related						
Change in Gross Margin due to Customer Growth	$ (4.6)		(3.7)			
Change in Use Rate	(4.7)		4.7			
Change in Other Revenue	(1.6)		(1.9)			
All Others	(1.8)	(12.7)	(1.5)	(2.4)	(15.1)	
O&M Forecast						
Change in overheads capitalized- change in O&M	(1.2)		(0.7)			
Change in O&M & Vehicle Lease Forecast	14.9	13.7	11.5	10.8	24.5	
Depreciation & Amortization Forecast						
After Tax Change in Depreciation from GPIS Additions/Retirements	3.7		2.3			
Change in Amortization	(2.2)	1.5	4.0	6.3	7.8	
Other						
Higher Property Taxes	1.6		1.0			
Change in Income Tax Expense	(0.4)		(0.1)			
Rate Base changes to support customer growth	1.8		2.5			
Interest Expense	2.1		5.4			
Rounding Difference	0.2	5.3	(0.1)	8.7	14.0	
Total Revenue Increase/(Decrease) Before Accounting Standard Changes		$ (14.6)		$ 23.4	$ 8.7	
Accounting Standard Changes						
Change in Overhead Capitalized Rate & Methodology	11.2		-			
Impacts on O&M	(0.3)	10.9	(2.0)	(2.0)	8.9	
After Tax change in Depreciation Rates	20.8		0.4			
After Tax change in Depreciation Commencement	1.9		-			
Tax Impacts of Depreciation Changes	9.0	31.7	0.1	0.5	32.2	
Total Revenue Increase from Accounting Standard Changes		$ 42.6		$ (1.5)	$ 41.1	
Net Revenue Increase - June 15, 2009 Application		**$ 27.9**		**$ 21.9**	**$ 49.8**	
Negotiatied Settlement Process Adjustments- please refer to Settlement Agreement for detail		(37.1)			(28.8)	
Adjusted Revenue (Decrease) / Increase		$ (9.2)	-1.73%		$ 21.0	3.93%
2010 Revenue Surplus deferred (pre-tax)*		9.2			(9.2)	
Net Revised Revenue (Decrease) / Increase- Negotiated Settlement Agreement Nov 5, 2009		**$ -**			**$ 11.8**	

*After Tax 2010 Revenue Surplus is $6.5 million

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
Tab 13
Schedule 2

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Core	2010 Non-Core	2010 Bypass and Special Rates	2010 Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$1,487,998	$1,430,710	$61,497	$12,094	$1,504,300	$16,302	- Tab C-13, Schedule 16
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue / Terasen Gas (Vancouver Island)	16,276	-	-	16,276	16,276	-	- Tab C-13, Schedule 26
8								
9	Total Revenue	1,504,274	1,430,710	61,497	28,369	1,520,576	16,302	
10								
11	Less - Cost of Gas	(975,597)	(986,394)	(759)	(817)	(987,970)	(12,373)	- Tab C-13, Schedule 19
12								
13	Gross Margin	$528,677	$444,316	$60,738	$27,552	$532,606	$3,929	
14								
15	Revenue Deficiency (Surplus)	$27,865	$0	$0	$0	**$0**	($27,865)	
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	5.27%	0.00%	0.00%	0.00%	0.00%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	1.85%	0.00%	0.00%	0.00%	0.00%		
20								

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
Tab 13
Schedule 3

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Core	2011 Non-Core	2011 Bypass and Special Rates	2011 Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$1,489,519	$1,433,011	$61,612	$12,094	$1,506,716	$17,197	- Tab C-13, Schedule 17
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue / Terasen Gas (Vancouver Island)	18,253	-	-	18,253	18,253	-	- Tab C-13, Schedule 27
8								
9	Total Revenue	1,507,772	1,433,011	61,612	30,347	1,524,969	17,197	
10								
11	Less - Cost of Gas	(976,614)	(988,047)	(759)	(821)	(989,627)	(13,013)	- Tab C-13, Schedule 21
12								
13	Gross Margin	$531,158	$444,964	$60,853	$29,526	$535,342	$4,184	
14								
15	Revenue Deficiency (Surplus)	$49,846	$10,340	$1,414	$0	**$11,754**	($38,092)	
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	9.38%	2.32%	2.32%	0.00%	2.20%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	3.31%	0.72%	2.30%	0.00%	0.77%		
20								

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C, Tab 13, Schedule 4

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing 2009 Rates	2010 ----Revised Rates----- Revised Revenue	2010 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	112,423	113,863	-	113,863	1,440	- Tab C-13, Schedule 14
3	Transportation	88,255	90,743	-	90,743	2,488	- Tab C-13, Schedule 14
4		200,678	204,606	-	204,606	3,928	
5							
6	Average Rate per GJ						
7	Sales	$12.801	$12.565	$0.000	$12.565	($0.236)	
8	Transportation	$0.869	$0.811	$0.000	$0.811	($0.058)	
9	Average	$7.554	$7.352	$0.000	$7.352	($0.202)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,414,636	$1,430,710	$0	$1,430,710	$16,074	- Tab C-13, Schedule 16
13	- Increase / (Decrease)	24,497	-	-	-	(24,497)	- Tab C-13, Schedule 22
14	RSAM Revenue						
15	Transportation - Existing Rates	73,362	73,591	-	73,591	229	- Tab C-13, Schedule 16
16	- Increase / (Decrease)	3,368		-	-	(3,368)	- Tab C-13, Schedule 22
17	**Total**	1,515,863	1,504,301	-	1,504,301	(11,562)	
18							
19	Cost of Gas Sold (Including Gas Lost)	975,597	987,970	-	987,970	12,373	- Tab C-13, Schedule 19
20							
21	**Gross Margin**	540,266	516,331	-	516,331	(23,935)	
22							
23	Operation and Maintenance	192,823	177,559	-	177,559	(15,264)	- Tab C-13, Schedule 28
24	Operating Leases	-	-	-	-	-	
25	Property and Sundry Taxes	49,193	49,193	-	49,193	-	- Tab C-13, Schedule 31
26	Depreciation and Amortization	103,796	88,893	-	88,893	(14,903)	- Tab C-13, Schedule 33
27	Removal Cost Provision		8,038	-	8,038	8,038	- Tab C-13, Schedule 33
28	Capitalized Depreciation		-	-	-	-	- Tab C-13, Schedule 33
29	NSP Provision (IFRS -$800 + ESM $225 + RSDA $6537)		5,963	-	5,963	5,963	
30	Other Operating Revenue	(22,422)	(22,455)	-	(22,455)	(33)	- Tab C-13, Schedule 26
31		323,390	307,191	-	307,191	(16,199)	
32	Utility Income Before Income Taxes	216,876	209,140	-	209,140	(7,736)	
33							
34	Income Taxes	31,622	24,923	-	24,923	(6,699)	- Tab C-13, Schedule 35
35							
36	**EARNED RETURN**	$185,254	$184,217	$0	$184,217	($1,037)	- Tab C-13, Schedule 10
37							
38							
39	**UTILITY RATE BASE**	$2,535,887	$2,534,444	$0	$2,534,444	($1,442)	- Tab C-13, Schedule 8
40							
41	**RATE OF RETURN ON UTILITY RATE BASE**	7.31%	7.27%		7.27%	-0.04%	- Tab C-13, Schedule 10

TERASEN GAS INC. — Nov 5, 2009 NSP Agreement — Section C, Tab 13, Schedule 5

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing 2009 Rates	2011 ----Revised Rates----- Revised Revenue	2011 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	112,326	113,846	-	113,846	1,520	- Tab C-13, Schedule 15
3	Transportation	88,438	91,014	-	91,014	2,576	- Tab C-13, Schedule 15
4		200,764	204,860	-	204,860	4,096	
5							
6	Average Rate per GJ						
7	Sales	$12.997	$12.587	$0.000	$12.678	($0.319)	
8	Transportation	$0.898	$0.810	$0.000	$0.825	($0.073)	
9	Average	$7.668	$7.355	$0.000	$7.412	($0.256)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,416,102	$1,433,011	$0	$1,433,011	$16,909	- Tab C-13, Schedule 17
13	- Increase / (Decrease)	43,822	-	10,341	10,341	(33,481)	- Tab C-13, Schedule 24
14							
15	Transportation - Existing Rates	73,417	73,705	-	73,705	288	- Tab C-13, Schedule 17
16	- Increase / (Decrease)	6,024		1,413	1,413	(4,611)	- Tab C-13, Schedule 24
17	**Total**	1,539,365	1,506,716	11,754	1,518,470	(20,895)	
18							
19	Cost of Gas Sold (Including Gas Lost)	976,614	989,627	-	989,627	13,013	- Tab C-13, Schedule 21
20							
21	**Gross Margin**	562,751	517,089	11,754	528,843	(33,908)	
22							
23	Operation and Maintenance	201,617	184,625	-	184,625	(16,992)	- Tab C-13, Schedule 28
24	Operating Leases	-	-	-	-	-	
25	Property and Sundry Taxes	50,211	50,211	-	50,211	-	- Tab C-13, Schedule 32
26	Depreciation and Amortization	110,496	88,588	-	88,588	(21,908)	- Tab C-13, Schedule 34
27	Removal Cost Provision		11,290	-	11,290	11,290	- Tab C-13, Schedule 34
28	Capitalized Depreciation		-	-	-	-	- Tab C-13, Schedule 34
29	NSP Provision (IFRS $800 + ESM $225)		1,025	-	1,025	1,025	
30	Other Operating Revenue	(24,359)	(24,394)	-	(24,394)	(35)	- Tab C-13, Schedule 27
31		337,965	311,345	-	311,345	(26,620)	
32	Utility Income Before Income Taxes	224,786	205,744	11,754	217,498	(7,288)	
33							
34	Income Taxes	31,654	21,449	3,115	24,564	(7,090)	- Tab C-13, Schedule 36
35							
36	**EARNED RETURN**	$193,132	$184,295	$8,639	$192,934	($198)	- Tab C-13, Schedule 11
37							
38							
39	**UTILITY RATE BASE**	$2,620,341	$2,628,766	$6	$2,628,772	$8,431	- Tab C-13, Schedule 9
40							
41	**RATE OF RETURN ON UTILITY RATE BASE**	7.37%	7.01%		7.34%	-0.03%	- Tab C-13, Schedule 11

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
Tab 13
Schedule 6

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

			2010				
				----Revised Rates-----			
Line No.	Particulars	June 15, 2009 Application	Existing 2009 Rates	Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$185,254	$184,217	$0	$184,217	($1,037)	- Tab C-13, Schedule 4
3	Deduct - Interest on Debt	(110,056)	(109,062)	-	(109,062)	994	- Tab C-13, Schedule 10
4	Add- Non-Tax Ded. Expense (Net)	(1,864)	(2,069)	-	(2,069)	(205)	- Tab C-13, Schedule 37
5	Accounting Income After Tax	73,334	73,086	-	73,086	(248)	
6	Add (Deduct) - Timing Differences	5,999	(4,958)	-	(4,958)	(10,957)	- Tab C-13, Schedule 37
7	Taxable Income After Tax	79,333	68,128	-	68,128	(11,205)	
8	Taxable Income Adj - SCP Landscaping Deduction	-	(7,834)	-	(7,834)	(7,834)	
9	Taxable Income Adj - Tax on SCP Landscaping	-	2,233	-	2,233	2,233	
10	Adjusted Taxable Income After Tax	$79,333	62,527	-	$62,527	(16,806)	
11							
12		28.500%	28.500%	28.500%	28.500%	0.000%	
13	1 - Current Income Tax Rate	71.500%	71.500%	71.500%	71.500%	0.000%	
14							
15	Taxable Income	$110,955	$87,450	$0	$87,450	($23,505)	
16							
17	**Total Income Tax**	$31,622	$24,923	$0	$24,923	($6,699)	
18							

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C Tab 13 Schedule 7

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing 2009 Rates	2011 ----Revised Rates----- Revised Revenue	2011 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$193,132	$184,295	$8,639	$192,934	($198)	- Tab C-13, Schedule 5
3	Deduct - Interest on Debt	(115,430)	(114,982)	-	(114,982)	448	- Tab C-13, Schedule 11
4	Add- Non-Tax Ded. Expense (Net)	1,974	(4,769)	-	(4,769)	(6,743)	- Tab C-13, Schedule 38
5	Accounting Income After Tax	79,676	64,544	8,639	73,183	(6,493)	
6	Add (Deduct) - Timing Differences	8,118	(5,053)	-	(5,053)	(13,171)	- Tab C-13, Schedule 38
7	Taxable Income After Tax	87,794	59,491	8,639	68,130	(19,664)	
8	Taxable Income Adjustment	-	-	-	-	-	
9	Taxable Income Adjustment	-	-	-	-	-	
10	Adjusted Taxable Income After Tax	$87,794	59,491	8,639	$68,130	(39,328)	
11							
12		26.500%	26.500%	26.500%	26.500%	0.000%	
13	1 - Current Income Tax Rate	73.500%	73.50%	73.500%	73.500%	0.000%	
14							
15	Taxable Income	$119,448	$80,940	$11,754	$92,694	($26,754)	
16							
17	**Total Income Tax**	$31,654	$21,449	$3,115	$24,564	($7,090)	(X-Ref - Tab C-13, Schedule 5)
18							

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
Tab 13
Schedule 8

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing 2009 Rates	2010 Adjustments	2010 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,317,590	$3,315,365	$0	$3,315,365	($2,225)	- Tab C-13, Schedule 45
2	Adjustment - CPCNs	-	-	-	-	-	- Tab C-13, Schedule 43
3	Gas Plant in Service, Ending	3,449,336	3,453,394	-	3,453,394	4,058	- Tab C-13, Schedule 45
4							
5	Accumulated Depreciation Beginning - Plant	($779,187)	($780,174)	$0	($780,174)	($987)	- Tab C-13, Schedule 49
6	Accumulated Depreciation Ending - Plant	(840,835)	(835,365)	-	(835,365)	5,470	- Tab C-13, Schedule 49
7							
8	CIAC, Beginning	($176,845)	($176,845)	$0	($176,845)	$0	- Tab C-13, Schedule 52
9	CIAC, Ending	(183,817)	(183,885)	-	(183,885)	(68)	- Tab C-13, Schedule 52
10							
11	Accumulated Amortization Beginning - CIAC	$44,146	$44,146	$0	$44,146	$0	- Tab C-13, Schedule 52
12	Accumulated Amortization Ending - CIAC	47,061	47,062	-	47,062	1	- Tab C-13, Schedule 52
13							
14	Net Plant in Service, Mid-Year	$2,438,725	$2,441,849	$0	$2,441,849	$3,125	
15							
16							
17	Adjustment to 13-Month Average	13,537	13,537	-	13,537	-	
18	Work in Progress, No AFUDC	15,627	15,627	-	15,627	-	
19	Unamortized Deferred Charges	(27,015)	(30,797)	-	(30,797)	(3,782)	- Tab C-13, Schedule 54
20	Cash Working Capital	(6,778)	(7,563)	-	(7,563)	(785)	- Tab C-13, Schedule 56
21	Other Working Capital (incl. Construction Advances)	103,439	103,439	-	103,439	-	- Tab C-13, Schedule 56
22	Future Income Taxes Regulatory Asset	284,455	284,455	-	284,455	-	- Tab C-13, Schedule 61
23	Future Income Taxes Regulatory Liability	(284,455)	(284,455)	-	(284,455)	-	- Tab C-13, Schedule 61
24	LILO Benefit	(1,648)	(1,648)	-	(1,648)	-	
25	**Utility Rate Base**	$2,535,887	$2,534,444	$0	$2,534,444	($1,442)	(X-Ref - Tab C-13, Schedule 10)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 9

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing 2009 Rates	Adjustments	Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,449,336	$3,453,394	$0	$3,453,394	$4,058	- Tab C-13, Schedule 47
2	Adjustment - CPCNs	-	-	-	-	-	
3	Gas Plant in Service, Ending	3,535,828	3,538,378	-	3,538,378	2,550	- Tab C-13, Schedule 47
4							
5	Accumulated Depreciation Beginning - Plant	($840,835)	($835,365)	$0	($835,365)	$5,470	- Tab C-13, Schedule 51
6	Accumulated Depreciation Ending - Plant	(899,386)	(885,651)	-	(885,651)	13,735	- Tab C-13, Schedule 51
7							
8	CIAC, Beginning	($183,817)	($183,885)	$0	($183,885)	($68)	- Tab C-13, Schedule 53
9	CIAC, Ending	(194,646)	(194,753)	-	(194,753)	(107)	- Tab C-13, Schedule 53
10							
11	Accumulated Amortization Beginning - CIAC	$47,061	$47,062	$0	$47,062	$1	- Tab C-13, Schedule 53
12	Accumulated Amortization Ending - CIAC	50,241	50,245	-	50,245	4	- Tab C-13, Schedule 53
13							
14	Net Plant in Service, Mid-Year	$2,481,891	$2,494,713	$0	$2,494,713	$12,822	
15							
16							
17	Adjustment to 13-Month Average	-	-	-	-	-	
18	Work in Progress, No AFUDC	15,627	15,627	-	15,627	-	
19	Unamortized Deferred Charges	10,347	6,770	-	6,770	(3,577)	- Tab C-13, Schedule 55
20	Cash Working Capital	(6,133)	(6,953)	6	(6,947)	(814)	- Tab C-13, Schedule 57
21	Other Working Capital (incl. Construction Advances)	120,091	120,091	-	120,091	-	- Tab C-13, Schedule 57
22	Future Income Taxes Regulatory Asset	292,155	292,155	-	292,155	-	- Tab C-13, Schedule 61
23	Future Income Taxes Regulatory Liability	(292,155)	(292,155)	-	(292,155)		- Tab C-13, Schedule 61
24	LILO Benefit	(1,482)	(1,482)	-	(1,482)	-	
25	**Utility Rate Base**	$2,620,341	$2,628,766	$6	$2,628,772	$8,431	(X-Ref - Tab C-13, Schedule 11)

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Reference	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2010 AT 2009 RATES							
2	Long-Term Debt	- Tab C-13, Schedule 64		$1,558,326	61.49%	6.870%	4.22%	
3	Unfunded Debt			88,809	3.50%	2.250%	0.08%	
4	Preference Shares			-	0.00%	0.000%	0.00%	
5	Common Equity			887,309	35.01%	8.483%	2.97%	
6								
7		- Tab C-13, Schedule 8		$2,534,444	100.00%		7.27%	
8								
9	2010 REVISED RATES							
10	Long-Term Debt	- Tab C-13, Schedule 64		$1,558,326	61.49%	6.870%	4.22%	$107,064
11	Unfunded Debt		$88,809					
12	Adjustment, Revised Rates		-	88,809	3.50%	2.250%	0.08%	1,998
13	Preference Shares			-	0.00%	0.000%	0.00%	-
14	Common Equity			887,309	35.01%	8.470%	2.97%	75,155
15		(X-Ref - Tab C-13, Schedule 4)						
16		- Tab C-13, Schedule 8		$2,534,444	100.00%		7.27%	$184,217

TERASEN GAS INC.

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Reference	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2011 AT 2009 RATES							
2	Long-Term Debt	- Tab C-13, Schedule 65		$1,631,453	62.06%	6.836%	4.24%	
3	Unfunded Debt			76,982	2.93%	4.500%	0.13%	
4	Preference Shares			-	0.00%	0.000%	0.00%	
5	Common Equity			920,331	35.01%	7.529%	2.64%	
6								
7		- Tab C-13, Schedule 9		$2,628,766	100.00%		7.01%	
8								
9	2011 REVISED RATES							
10	Long-Term Debt	- Tab C-13, Schedule 64		$1,631,453	62.06%	6.836%	4.24%	$111,518
11	Unfunded Debt		$76,982					
12	Adjustment, Revised Rates		4	76,986	2.93%	4.500%	0.13%	3,464
13	Preference Shares			-	0.00%	0.000%	0.00%	-
14	Common Equity			920,333	35.01%	8.470%	2.97%	77,952
15		(X-Ref - Tab C-13, Schedule 5)						
16		- Tab C-13, Schedule 9		$2,628,772	100.00%		7.34%	$192,934

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
Tab 13
Schedule 12

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing 2009 Rates	2010 ----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	112,423	113,863	-	113,863	1,440	- Tab C-13, Schedule 14
3	Transportation	88,255	90,743	-	90,743	2,488	- Tab C-13, Schedule 14
4		200,678	204,606	-	204,606	3,928	
5							
6	Average Rate per GJ						
7	Sales	$12.801	$12.565	$0.000	$12.565	($0.236)	
8	Transportation	$0.869	$0.811	$0.000	$0.811	($0.058)	
9	Average	$7.554	$7.352	$0.000	$7.352	($0.202)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,414,636	$1,430,710	$0	$1,430,710	$16,074	- Tab C-13, Schedule 16
13	- Increase / (Decrease)	24,497	-	-	-	(24,497)	- Tab C-13, Schedule 22
14		-					
15	Transportation - Existing Rates	73,362	73,591	-	73,591	229	- Tab C-13, Schedule 16
16	- Increase / (Decrease)	3,368		-	-	(3,368)	- Tab C-13, Schedule 22
17	**Total**	1,515,863	1,504,301	-	1,504,301	(11,562)	
18							
19	Cost of Gas Sold (Including Gas Lost)	975,597	987,970	-	987,970	12,373	- Tab C-13, Schedule 19
20							
21	**Gross Margin**	540,266	516,331	-	516,331	(23,935)	
22							
23	Operation and Maintenance	192,823	177,559	-	177,559	(15,264)	- Tab C-13, Schedule 28
24	Vehicle Lease	-	-	-	-	-	
25	Property and Sundry Taxes	49,193	49,193	-	49,193	-	- Tab C-13, Schedule 31
26	Depreciation and Amortization	103,796	88,893	-	88,893	(14,903)	- Tab C-13, Schedule 33
27	Removal Cost Provision		8,038	-	8,038	8,038	- Tab C-13, Schedule 33
28	Capitalized Depreciation		-	-	-	-	- Tab C-13, Schedule 33
29	NSP Provision (IFRS -$800 + ESM $225 + RSDA $6537)		5,963	-	5,963	5,963	
30	Other Operating Revenue	(22,422)	(22,455)	-	(22,455)	(33)	- Tab C-13, Schedule 26
31		323,390	307,191	-	307,191	(16,199)	
32	Utility Income Before Income Taxes	216,876	209,140	-	209,140	(7,736)	
33							
34	Income Taxes	31,622	24,923	-	24,923	(6,699)	- Tab C-13, Schedule 35
35							
36	**EARNED RETURN**	$185,254	$184,217	$0	$184,217	($1,037)	- Tab C-13, Schedule 10
37							
38							
39	**UTILITY RATE BASE**	$2,535,887	$2,534,444	$0	$2,534,444	($1,442)	- Tab C-13, Schedule 8
40							
41	**RATE OF RETURN ON UTILITY RATE BASE**	7.31%	7.27%		7.27%	-0.04%	- Tab C-13, Schedule 10

TERASEN GAS INC.　　Nov 5, 2009 NSP Agreement　　Section C
Tab 13
Schedule 13

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing 2009 Rates	----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	112,326	113,846	-	113,846	1,520	- Tab C-13, Schedule 15
3	Transportation	88,438	91,014	-	91,014	2,576	- Tab C-13, Schedule 15
4		200,764	204,860	-	204,860	4,096	
5							
6	Average Rate per GJ						
7	Sales	$12.997	$12.587	$0.000	$12.678	($0.319)	
8	Transportation	$0.898	$0.810	$0.000	$0.825	($0.073)	
9	Average	$7.668	$7.355	$0.000	$7.412	($0.256)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,416,102	$1,433,011	$0	$1,433,011	$16,909	- Tab C-13, Schedule 17
13	- Increase / (Decrease)	43,822	-	10,341	10,341	(33,481)	- Tab C-13, Schedule 24
14		-					
15	Transportation - Existing Rates	73,417	73,705	-	73,705	288	- Tab C-13, Schedule 17
16	- Increase / (Decrease)	6,024		1,413	1,413	(4,611)	- Tab C-13, Schedule 24
17	**Total**	1,539,365	1,506,716	11,754	1,518,470	(20,895)	
18							
19	Cost of Gas Sold (Including Gas Lost)	976,614	989,627	-	989,627	13,013	- Tab C-13, Schedule 21
20							
21	**Gross Margin**	562,751	517,089	11,754	528,843	(33,908)	
22							
23	Operation and Maintenance	201,617	184,625	-	184,625	(16,992)	- Tab C-13, Schedule 28
24	Vehicle Lease	-	-	-	-	-	
25	Property and Sundry Taxes	50,211	50,211	-	50,211	-	- Tab C-13, Schedule 32
26	Depreciation and Amortization	110,496	88,588	-	88,588	(21,908)	- Tab C-13, Schedule 34
27	Removal Cost Provision		11,290	-	11,290	11,290	- Tab C-13, Schedule 34
28	Capitalized Depreciation		-	-	-	-	- Tab C-13, Schedule 34
29	NSP Provision (IFRS $800 + ESM $225)		1,025	-	1,025	1,025	
30	Other Operating Revenue	(24,359)	(24,394)	-	(24,394)	(35)	- Tab C-13, Schedule 27
31		337,965	311,345	-	311,345	(26,620)	
32	Utility Income Before Income Taxes	224,786	205,744	11,754	217,498	(7,288)	
33							
34	Income Taxes	31,654	21,449	3,115	24,564	(7,090)	- Tab C-13, Schedule 36
35							
36	**EARNED RETURN**	$193,132	$184,295	$8,639	$192,934	($198)	- Tab C-13, Schedule 11
37							
38							
39	**UTILITY RATE BASE**	$2,620,341	$2,628,766	$6	$2,628,772	$8,431	- Tab C-13, Schedule 9
40							
41	**RATE OF RETURN ON UTILITY RATE BASE**	7.37%	7.01%		7.34%	-0.03%	- Tab C-13, Schedule 11

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C Tab 13 Schedule 14

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2010

Line No.	Particulars	June 15, 2009 Application	2010 Terajoules Core and Non-Core	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	67,829.2	69,174.3	0.0	69,174.3	1,345.1	
3	Schedule 2 - Small Commercial	24,374.3	24,374.3		24,374.3	0.0	
4	Schedule 3 - Large Commercial	16,818.6	16,818.6		16,818.6	0.0	
5							
6	Schedules 1, 2 and 3	109,022.1	110,367.2	0.0	110,367.2	1,345.1	
7							
8	Schedule 4 - Seasonal	184.6	184.6		184.6	0.0	
9	Schedule 5 - General Firm	3,098.5	3,184.6		3,184.6	86.1	
10							
11	Industrials	0.0					
12	Schedule 7 - Interruptible	14.2	22.7		22.7	8.5	
13							
14	Schedule 6 - N G V Fuel - Stations	103.8	103.8		103.8	0.0	
15							
16	Total Sales	112,423.2	113,862.9	0.0	113,862.9	1,439.7	(X-Ref - Tab C-13, Schedule 4)
17							
18	**TRANSPORTATION SERVICE**						
19	Schedule 22 - Firm Service	13,090.4	8,103.2	7,795.6	15,898.8	2,808.4	
20	- Interruptible Service	11,849.7	11,080.5	0.0	11,080.5	(769.2)	
21	Byron Creek (aka Fording Coal Mountain)	125.8		137.5	137.5	11.7	
22	Burrard Thermal - Firm	2,343.9		1,719.4	1,719.4	(624.5)	
23	TGVI - Firm	36,368.3		36,368.3	36,368.3	0.0	
24	Schedule 23 - Large Commercial	6,134.0	6,134.0		6,134.0	0.0	
25	Schedule 25 - Firm Service	13,159.6	12,944.4	873.1	13,817.5	657.9	
26	Schedule 27 - Interruptible Service	5,183.5	5,587.4		5,587.4	403.9	
22							
23	Total Transportation Service	88,255.2	43,849.5	46,893.9	90,743.4	2,488.2	(X-Ref - Tab C-13, Schedule 4)
24							
25	**TOTAL SALES AND TRANSPORTATION SERVICES**	200,678.4	157,712.4	46,893.9	204,606.3	3,927.9	(X-Ref - Tab C-13, Schedule 23)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement

Section C
Tab 13
Schedule 15

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2011

			2011 Terajoules				
Line No.	Particulars	June 15, 2009 Application	Core and Non-Core	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	67,190.5	68,578.9	0.0	68,578.9	1,388.4	
3	Schedule 2 - Small Commercial	24,603.1	24,603.1		24,603.1	0.0	
4	Schedule 3 - Large Commercial	17,168.5	17,168.5		17,168.5	0.0	
5							
6	Schedules 1, 2 and 3	108,962.1	110,350.5	0.0	110,350.5	1,388.4	
7							
8	Schedule 4 - Seasonal	184.6	184.6		184.6	0.0	
9	Schedule 5 - General Firm	3,061.2	3,184.3		3,184.3	123.1	
10							
11	Industrials	0.0					
12	Schedule 7 - Interruptible	14.2	22.7		22.7	8.5	
13							
14	Schedule 6 - N G V Fuel - Stations	103.8	103.8		103.8	0.0	
15							
16	Total Sales	112,325.9	113,845.9	0.0	113,845.9	1,520.0	(X-Ref - Tab C-13, Schedule 5)
17							
18	**TRANSPORTATION SERVICE**						
19	Schedule 22 - Firm Service	13,090.4	8,103.2	7,795.6	15,898.8	2,808.4	
20	- Interruptible Service	11,830.5	11,080.5	0.0	11,080.5	(750.0)	
21	Byron Creek (aka Fording Coal Mountain)	125.8		137.5	137.5	11.7	
22	Burrard Thermal - Firm	2,343.9		1,719.4	1,719.4	(624.5)	
23	TGVI - Firm	36,596.4		36,596.4	36,596.4	0.0	
24	Schedule 23 - Large Commercial	6,177.2	6,177.2		6,177.2	0.0	
25	Schedule 25 - Firm Service	13,102.0	12,944.1	873.1	13,817.2	715.2	
26	Schedule 27 - Interruptible Service	5,171.9	5,587.4		5,587.4	415.5	
22							
23	Total Transportation Service	88,438.1	43,892.4	47,122.0	91,014.4	2,576.3	(X-Ref - Tab C-13, Schedule 5)
24							
25	**TOTAL SALES AND TRANSPORTATION SERVICES**	200,764.0	157,738.3	47,122.0	204,860.3	4,096.3	(X-Ref - Tab C-13, Schedule 25)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 16

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Gas Sales Revenue At Existing 2009 Rates: Core and Non-Core	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**Core Sales**						
2	Schedule 1 - Residential	$897,420	$912,822	$0	$912,822	$15,402	
3	Schedule 2 - Small Commercial	297,556	297,556		297,556	-	
4	Schedule 3 - Large Commercial	189,604	189,604		189,604	-	
5	Schedules 1, 2 and 3	1,384,580	1,399,982	-	1,399,982	15,402	
6							
7	Schedule 4 - Seasonal	1,477	1,477	-	1,477	-	
8	Schedule 5 - General Firm	27,404	28,012		28,012	609	
9		28,881	29,490	-	29,490	609	
10	Industrials						
11	Interruptible - Schedule 7	130	194	-	194	64	
12							
13	N G V Fuel - Stations - Schedule 6	1,044	1,044		1,044	-	
14							
15	Total Core Sales	1,414,636	1,430,710	-	1,430,710	16,074	(X-Ref - Tab C-13, Schedule 4)
16							(X-Ref - Tab C-13, Schedule 12)
17	**Transportation Service**						
18	Schedule 22 - Firm Service	6,380	5,189	1,270	6,459	79	
19	- Interruptible Service	9,743	9,270	-	9,270	(473)	
20	Byron Creek (aka Fording Coal Mountain)	53		53	53	-	
21	Burrard Thermal - Firm	9,996		9,996	9,996	-	
22	TGVI - Firm	-		-	-	-	
23	Schedule 23 - Large Commercial	16,411	16,411	-	16,411	-	
24	Schedule 25 - Firm Service	24,509	23,970	775	24,744	235	
25	Schedule 27 - Interruptible Service	6,270	6,658	-	6,658	388	
26	Total T-Service	73,362	61,497	12,094	73,591	229	(X-Ref - Tab C-13, Schedule 4)
27							(X-Ref - Tab C-13, Schedule 12)
28	TOTAL SALES AND TRANSPORTATION SERVICE	$1,487,998	$1,492,207	$12,094	$1,504,300	$16,302	(X-Ref - Tab C-13, Schedule 23)

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Gas Sales Revenue At Existing 2009 Rates: Core and Non-Core	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**Core Sales**						
2	Schedule 1 - Residential	$891,764	$907,735	$0	$907,735	$15,971	
3	Schedule 2 - Small Commercial	300,831	300,831		300,831	-	
4	Schedule 3 - Large Commercial	193,720	193,720		193,720	-	
5	Schedules 1, 2 and 3	1,386,315	1,402,286	-	1,402,286	15,971	
6							
7	Schedule 4 - Seasonal	1,477	1,477	-	1,477	-	
8	Schedule 5 - General Firm	27,135	28,009		28,009	874	
9		28,613	29,487	-	29,487	874	
10	Industrials						
11	Interruptible - Schedule 7	130	194	-	194	64	
12							
13	N G V Fuel - Stations - Schedule 6	1,044	1,044		1,044	-	
14							
15	Total Core Sales	1,416,102	1,433,011	-	1,433,011	16,908	- Tab C-13, Schedule 5
16							(X-Ref - Tab C-13, Schedule 13)
17	**Transportation Service**						
18	Schedule 22 - Firm Service	6,380	5,189	1,270	6,459	79	
19	- Interruptible Service	9,729	9,270	-	9,270	(459)	
20	Byron Creek (aka Fording Coal Mountain)	53		53	53	-	
21	Burrard Thermal - Firm	9,996		9,996	9,996	-	
22	TGVI - Firm	-		-	-	-	
23	Schedule 23 - Large Commercial	16,525	16,525	-	16,525	-	
24	Schedule 25 - Firm Service	24,475	23,969	775	24,744	269	
25	Schedule 27 - Interruptible Service	6,258	6,658	-	6,658	400	
26	Total T-Service	73,417	61,612	12,094	73,705	288	- Tab C-13, Schedule 5
27							(X-Ref - Tab C-13, Schedule 13)
28	TOTAL SALES AND TRANSPORTATION SERVICE	$1,489,519	$1,494,622	$12,094	$1,506,716	$17,197	(X-Ref - Tab C-13, Schedule 25)

COST OF GAS BY RATE SCHEDULE - Summary by Service Area (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2010

		Lower Mainland			Inland Including Revelstoke			Columbia			Total
Line No.	Particulars	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000s)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000s)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000s)	Cost of Gas ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**Non-Bypass CORE AND NON-CORE**										
2	Core Sales										
3	Schedule 1 - Residential	51,798.7	$8.830	$457,371	15,692.9	$8.325	$130,649	1,682.7	$8.394	$14,124	$602,144
4	Schedule 2 - Small Commercial	17,866.8	8.972	160,297	5,791.0	8.449	48,931	716.5	8.554	6,129	215,357
5	Schedule 3 - Large Commercial	13,802.1	8.756	120,855	2,703.0	8.260	22,327	313.5	8.140	2,552	145,734
6	Schedules 1, 2 and 3	83,467.6		738,523	24,186.9		201,907	2,712.7		22,805	963,235
7											
8	Schedule 4 - Seasonal	87.8	6.701	588	96.8	6.622	641	-	-	-	1,229
9	Schedule 5 - General Firm	2,729.0	6.632	18,099	415.7	6.608	2,747	39.9	6.677	266	21,112
10											
11	Industrials										
12	Interruptible - Schedule 7	-	-	-	22.7	6.608	150	-	-	-	150
13											
14	N G V Fuel - Stations - Schedule 6	92.0	6.447	593	11.8	6.356	75	-	-	-	668
15											
16	Total Core Sales	86,376.4		757,803	24,733.9		205,520	2,752.6		23,071	986,394
17											
18	Transportation Service										
19	Schedule 22 - Firm Service	-	-	-	5,514.3	0.017	94	2,588.9	0.081	210	304
20	- Interruptible Service	10,726.2	0.007	71	329.1	0.365	120	25.2	-	-	191
21	Schedule 23 - Large Commercial	4,950.9	0.008	40	1,124.1	0.016	18	59.0	0.080	5	63
22	Schedule 25 - Firm Service	9,356.3	0.008	75	3,318.8	0.016	53	269.3	0.080	22	150
23	Schedule 27 - Interruptible Service	4,820.0	0.008	39	747.7	0.016	12	19.7	-	-	51
24	Total T-Service	29,853.4		225	11,034.0		297	2,962.1		237	759
25	**Total Non-Bypass Sales and Transportation Service**										
26	**Cost of Gas Sold**	116,229.8		$758,028	35,767.9		$205,817	5,714.7		$23,308	$987,153

COST OF GAS BY RATE SCHEDULE - Summary by Service Area (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2010

		Lower Mainland			Inland Including Revelstoke			Columbia			Total
Line No.	Particulars	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000s)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000s)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000s)	Cost of Gas ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	-	-	15	7,475.8	-	-	319.8	0.050	16	31
4	- Interruptible Service	-	-	-	-	-	-	-	-	-	-
5	Byron Creek (aka Fording Coal Mountain)	-	-	-	-	-	-	137.5	0.049	7	7
6	Burrard Thermal - Firm	1,719.4	0.020	35	-	-	-	-	-	-	35
7	TGVI - Firm	36,368.3	0.020	730	-	-	-	-	-	-	730
8	Schedule 23 - Large Commercial				-	-	-				-
9	Schedule 25 - Firm Service	-	-	-	873.1	0.016	14	-	-	-	14
10	Schedule 27 - Interruptible Service				-	-	-				-
11	**Total Bypass and Spec. Rates T-Svc**	38,087.7		780	8,348.9		14	457.3		23	817
12											
13	**Total Non-Bypass and Bypass Sales and Transportation Service**										
14	**Cost of Gas Sold**	154,317.5		$758,808	44,116.8		$205,831	6,172.0		$23,331	$987,970

(X-Ref - Tab C-13, Schedule 12) , (X-Ref - Tab C-13, Schedule 4)

COST OF GAS BY RATE SCHEDULE - Summary by Service Area (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2011

Line No.	Particulars	Lower Mainland Energy TJ	Lower Mainland Unit Cost $/GJ	Lower Mainland Cost of Gas ($000s)	Inland Including Revelstoke Energy TJ	Inland Including Revelstoke Unit Cost $/GJ	Inland Including Revelstoke Cost of Gas ($000s)	Columbia Energy TJ	Columbia Unit Cost $/GJ	Columbia Cost of Gas ($000s)	Total Cost of Gas ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**Non-Bypass CORE AND NON-CORE**										
2	Core Sales										
3	Schedule 1 - Residential	51,350.2	$8.846	$454,251	15,555.0	$8.342	$129,766	1,673.7	$8.410	$14,076	$598,093
4	Schedule 2 - Small Commercial	18,027.1	8.991	162,072	5,851.0	8.471	49,566	725.0	8.580	6,221	217,859
5	Schedule 3 - Large Commercial	14,042.4	8.770	123,157	2,801.4	8.259	23,136	324.7	8.149	2,646	148,939
6	Schedules 1, 2 and 3	83,419.7		739,480	24,207.4		202,468	2,723.4		22,943	964,891
7											
8	Schedule 4 - Seasonal	87.8	6.701	588	96.8	6.622	641	-	-	-	1,229
9	Schedule 5 - General Firm	2,728.9	6.632	18,098	415.5	6.606	2,745	39.9	6.677	266	21,109
10											
11	Industrials										
12	Interruptible - Schedule 7	-	-	-	22.7	6.608	150	-	-	-	150
13											
14	N G V Fuel - Stations - Schedule 6	92.0	6.447	593	11.8	6.356	75	-	-	-	668
15											
16	Total Core Sales	86,328.4		758,759	24,754.2		206,079	2,763.3		23,209	988,047
17											
18	Transportation Service										
19	Schedule 22 - Firm Service	-	-	-	5,514.3	0.017	94	2,588.9	0.081	210	304
20	- Interruptible Service	10,726.2	0.007	71	329.1	0.365	120	25.2	-	-	191
21	Schedule 23 - Large Commercial	4,974.0	0.008	40	1,144.2	0.016	18	59.0	0.080	5	63
22	Schedule 25 - Firm Service	9,356.0	0.008	75	3,318.8	0.016	53	269.3	0.080	22	150
23	Schedule 27 - Interruptible Service	4,820.0	0.008	39	747.7	0.016	12	19.7	-	-	51
24	Total T-Service	29,876.2		225	11,054.1		297	2,962.1		237	759
25	**Total Non-Bypass Sales and Transportation Service**										
26	**Cost of Gas Sold**	116,204.6		$758,984	35,808.3		$206,376	5,725.4		$23,446	$988,806

TERASEN GAS INC.

COST OF GAS BY RATE SCHEDULE - Summary by Service Area (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2011

Line No.	Particulars	Lower Mainland Energy TJ	Lower Mainland Unit Cost $/GJ	Lower Mainland Cost of Gas ($000s)	Inland Including Revelstoke Energy TJ	Inland Including Revelstoke Unit Cost $/GJ	Inland Including Revelstoke Cost of Gas ($000s)	Columbia Energy TJ	Columbia Unit Cost $/GJ	Columbia Cost of Gas ($000s)	Total Cost of Gas ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	-	-	15	7,475.8	-	-	319.8	0.056	18	33
4	- Interruptible Service	-	-	-	-	-	-	-	-	-	-
5	Byron Creek (aka Fording Coal Mountain)	-	-	-	-	-	-	137.5	0.032	4	4
6	Burrard Thermal - Firm	1,719.4	0.020	35	-	-	-	-	-	-	35
7	TGVI - Firm	36,596.4	0.020	735	-	-	-	-	-	-	735
8	Schedule 23 - Large Commercial				-	-	-				-
9	Schedule 25 - Firm Service	-	-	-	873.1	0.016	14	-	-	-	14
10	Schedule 27 - Interruptible Service				-	-	-				-
11	**Total Bypass and Spec. Rates T-Svc**	38,315.8		785	8,348.9		14	457.3		22	821
12											
13	**Total Non-Bypass and Bypass Sales and Transportation Service**										
14	**Cost of Gas Sold**	154,520.4		$759,769	44,157.2		$206,390	6,182.7		$23,468	$989,627

(X-Ref - Tab C-13, Schedule 13) , (X-Ref - Tab C-13, Schedule 5)

TERASEN GAS INC.

REVENUE UNDER EXISTING 2009 RATES AND REVISED 2010 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

			Revenue -- At Existing 2009 Rates --		Gross Margin -- At Existing 2009 Rates --		Effective Increase / (Decrease) 0.00% of Margin			Revenue ---- Revised Rates ----	
Line No.	Particulars	Terajoules	Average $/GJ	Revenue ($000s)	Average $/GJ	Margin ($000s)	$/GJ	Revenue ($000s)	Average Number of Customers	Average $/GJ	Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Core Sales										
3	Schedule 1 - Residential	69,174.3	$13.196	$912,822	$4.491	$310,678	$0.000	$0	754,076	$13.196	$912,822
4	Schedule 2 - Small Commercial	24,374.3	12.208	297,556	3.372	82,200	-	0	76,536	12.208	297,556
5	Schedule 3 - Large Commercial	16,818.6	11.273	189,604	2.608	43,870	-	0	5,022	11.273	189,604
6	Total Schedules 1 , 2 and 3	110,367.2		1,399,982		436,747		0	835,633		1,399,982
7											
8	Schedule 4 - Seasonal Service	184.6	8.003	1,477	1.343	248	-	0	16	8.003	1,477
9	Schedule 5 - General Firm Service	3,184.6	8.796	28,012	2.167	6,901	-	0	281	8.796	28,012
10											
11	Industrials										
12	Schedule 7 - Interruptible	22.7	8.542	194	1.938	44	-	0	2	8.542	194
13											
14	Schedule 6 - N G V Fuel - Stations	103.8	10.062	1,044	3.628	377	-	0	32	10.062	1,044
15											
16	Total Core Sales	113,862.9		1,430,710		444,316		0	835,964		1,430,710
17											
18	Transportation Service										
19	Schedule 22 - Firm Service	8,103.2	0.640	5,189	0.603	4,885	-	0	13	0.640	5,189
20	- Interruptible Service	11,080.5	0.837	9,270	0.819	9,079	-	0	22	0.837	9,270
21	Schedule 23 - Large Commercial	6,134.0	2.675	16,411	2.665	16,348	-	0	1,309	2.675	16,411
22	Schedule 25 - Firm Service	12,944.4	1.852	23,970	1.840	23,820	-	0	573	1.852	23,970
23	Schedule 27 - Interruptible Service	5,587.4	1.192	6,658	1.183	6,607	-	0	98	1.192	6,658
24											
25	Total T-Service	43,849.5		61,497		60,739		0	2,015		61,497
26											
27	Total Non-Bypass Sales & Transportation Service	157,712.4		$1,492,207		$505,055		$0	837,979		$1,492,207
28		(X-Ref - Tab C-13, Schedule 14)		(X-Ref - Tab C-13, Schedule 16)				(X-Ref - Tab C-13, Schedule 2)			

REVENUE UNDER EXISTING 2009 RATES AND REVISED 2010 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2009 Rates -- Average $/GJ	Revenue ($000)	Gross Margin -- At Existing 2009 Rates -- Average $/GJ	Margin ($000s)	Increase / (Decrease) 0.00% of Margin $/GJ	Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	7,795.6	0.163	1,270	0.159	1,239	-	-	8	0.163	1,270
4	- Interruptible Service	-	-	-	-	-	-	-	1	-	-
5	Byron Creek (aka Fording Coal Mountain)	137.5	0.386	53	0.338	46	-	-	1	0.386	53
6	Burrard Thermal - Firm	1,719.4	5.814	9,996	5.794	9,962	-	-	1		9,996
7	TGVI - Firm	36,368.3	-	-	-	-	-	-	1	-	-
8	Schedule 23 - Large Commercial	-		-		-		-	-	-	-
9	Schedule 25 - Firm Service	873.1	0.887	775	0.871	761	-	-	7	0.887	775
10	Schedule 27 - Interruptible Service	-		-		-		-	-	-	-
11	Total Bypass and Spec. Rates T-Svc	46,893.9		12,094		12,008		-	19		12,094
12											
13	Total Bypass Sales and										
14	Transportation Service	46,893.9		12,094		12,008		-	19		12,094
15											
16	TOTAL NON-BYPASS AND BYPASS SALES AND										
17	TRANSPORTATION SERVICE	204,606.3		$1,504,300		$517,063		$0	837,998		$1,504,300
18		(X-Ref - Tab C-13, Schedule 14)		(X-Ref - Tab C-13, Schedule 16)			(X-Ref - Tab C-13, Schedule 2)				

REVENUE UNDER EXISTING 2009 RATES AND REVISED 2011 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2009 Rates -- Average $/GJ	Revenue -- At Existing 2009 Rates -- Revenue ($000)	Gross Margin -- At Existing 2009 Rates -- Average $/GJ	Gross Margin -- At Existing 2009 Rates -- Margin ($000s)	Effective Increase / (Decrease) 2.32% of Margin $/GJ	Effective Increase / (Decrease) 2.32% of Margin Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ---- Revised Rates ---- Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Core Sales										
3	Schedule 1 - Residential	68,578.9	$13.236	$907,735	$4.515	$309,643	$0.105	$7,196	759,267	$13.341	$914,931
4	Schedule 2 - Small Commercial	24,603.1	12.227	300,831	3.372	82,972	0.078	1,928	77,252	12.305	302,759
5	Schedule 3 - Large Commercial	17,168.5	11.283	193,720	2.608	44,781	0.061	1,040	5,126	11.344	194,760
6	Total Schedules 1 , 2 and 3	110,350.5		1,402,286		437,395		10,164	841,644		1,412,450
7											
8	Schedule 4 - Seasonal Service	184.6	8.0030	1,477	1.3430	248	0.0330	6	16	8.036	1,483
9	Schedule 5 - General Firm Service	3,184.3	8.7960	28,009	2.1670	6,900	0.0510	161	281	8.847	28,170
10											
11	Industrials										
12	Schedule 7 - Interruptible	22.7	8.5420	194	1.9380	44	0.0440	1	2	8.586	195
13											
14	Schedule 6 - N G V Fuel - Stations	103.8	10.0620	1,044	3.6280	377	0.0870	9	32	10.149	1,053
15											
16	Total Core Sales	113,845.9		1,433,011		444,964		10,341	841,975		1,443,352
17											
18	Transportation Service										
19	Schedule 22 - Firm Service	8,103.2	0.6400	5,189	0.6030	4,885	0.0140	113	13	0.654	5,302
20	- Interruptible Service	11,080.5	0.8370	9,270	0.8190	9,079	0.0190	210	22	0.856	9,480
21	Schedule 23 - Large Commercial	6,177.2	2.6750	16,525	2.6650	16,462	0.0620	383	1,318	2.737	16,908
22	Schedule 25 - Firm Service	12,944.1	1.8520	23,969	1.8400	23,819	0.0430	554	573	1.895	24,523
23	Schedule 27 - Interruptible Service	5,587.4	1.1920	6,658	1.1830	6,607	0.0270	153	98	1.219	6,811
24											
25	Total T-Service	43,892.4		61,612		60,853		1,413	2,024		63,025
26											
27	Total Non-Bypass Sales & Transportation Service	157,738.3		$1,494,622		$505,817		$11,754	843,999		$1,506,376
28		(X-Ref - Tab C-13, Schedule 15)		(X-Ref - Tab C-13, Schedule 17)			(X-Ref - Tab C-13, Schedule 3)				

REVENUE UNDER EXISTING 2009 RATES AND REVISED 2011 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2009 Rates -- Average $/GJ	Revenue ($000)	Gross Margin -- At Existing 2009 Rates -- Average $/GJ	Margin ($000s)	Increase / (Decrease) 2.32% of Margin $/GJ	Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	7,795.6	0.1630	1,270	0.1587	1,237	-	-	8	0.1630	1,270
4	- Interruptible Service	-	-	-	-	-	-	-	1	-	-
5	Byron Creek (aka Fording Coal Mountain)	137.5	0.3860	53	0.3543	49	-	-	1	0.3860	53
6	Burrard Thermal - Firm	1,719.4	5.8140	9,996	5.7936	9,962	-	-	1	5.8140	9,996
7	TGVI - Firm	36,596.4	-	-	-	-	-	-	1	-	-
8	Schedule 23 - Large Commercial	-		-		-		-	-	-	-
9	Schedule 25 - Firm Service	873.1	0.8870	775	0.8711	761	-	-	7	0.8870	775
10	Schedule 27 - Interruptible Service	-		-		-		-	-	-	-
11	Total Bypass and Spec. Rates T-Svc	47,122.0		12,094		12,008		-	19		12,094
12											
13	Total Bypass Sales and										
14	Transportation Service	47,122.0		12,094		12,008		-	19		12,094
15											
16	TOTAL NON-BYPASS AND BYPASS SALES AND										
17	TRANSPORTATION SERVICE	204,860.3		$1,506,716		$517,825		$11,754	844,018		$1,518,470
18		(X-Ref - Tab C-13, Schedule 15)		(X-Ref - Tab C-13, Schedule 17)			(X-Ref - Tab C-13, Schedule 3)				

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
Tab 13
Schedule 26

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$2,982	$3,014	$32	(X-Ref - Tab C-13, Schedule 59)
4					
5	Connection Charge	2,879	2,880	1	(X-Ref - Tab C-13, Schedule 59)
6					
7	NSF Returned Cheque Charges	82	82	-	(X-Ref - Tab C-13, Schedule 59)
8					
9	Other Recoveries	74	74	-	(X-Ref - Tab C-13, Schedule 59)
10					
11	Total Other Utility Revenue	6,017	6,050	33	
12					
13	**Miscellaneous Revenue**				
14					
15	TGVI Wheeling Charge	3,457	3,457	-	(X-Ref - Tab C-13, Schedule 2)
16					
17	SCP Third Party Revenue	12,819	12,819	-	(X-Ref - Tab C-13, Schedule 2)
18					
19	TGVI SAP Lease Income	129	129	-	(X-Ref - Tab C-13, Schedule 59)
20					
21					
22	Total Miscellaneous	16,405	16,405	-	
23					(X-Ref - Tab C-13, Schedule 12)
24	**Total Other Operating Revenue**	$22,422	$22,455	$33	(X-Ref - Tab C-13, Schedule 4)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 27

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000)

Line No.	Particulars	June 15, 2009 Application	2011	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$2,987	$3,020	$33	(X-Ref - Tab C-13, Schedule 59)
4					
5	Connection Charge	2,905	2,907	2	(X-Ref - Tab C-13, Schedule 59)
6					
7	NSF Returned Cheque Charges	82	82	-	(X-Ref - Tab C-13, Schedule 59)
8					
9	Other Recoveries	76	76	-	(X-Ref - Tab C-13, Schedule 59)
10					
11	Total Other Utility Revenue	6,050	6,085	35	
12					
13	**Miscellaneous Revenue**				
14					
15	TGVI Wheeling Charge	3,455	3,455	-	(X-Ref - Tab C-13, Schedule 3)
16					
17	SCP Third Party Revenue	14,798	14,798	-	(X-Ref - Tab C-13, Schedule 3)
18					
19	TGVI SAP Lease Income	56	56	-	(X-Ref - Tab C-13, Schedule 59)
20					
21					
22	Total Miscellaneous	18,309	18,309	-	
23					(X-Ref - Tab C-13, Schedule 13)
24	**Total Other Operating Revenue**	$24,359	$24,394	$35	(X-Ref - Tab C-13, Schedule 5)

TERASEN GAS INC — Nov 5, 2009 NSP Agreement — Section C, Tab 13, Schedule 28

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000)

Line No.	Particulars	PROJECTION 2009	FORECAST 2010	FORECAST 2011	Reference
	(1)	(2)	(3)	(4)	(5)
1	M&E Costs	$ 43,087	$ 45,496	$ 48,663	
2	COPE Costs	24,792	29,505	31,938	
3	IBEW Costs	22,301	24,870	26,559	
4					
5	**Labour Costs**	**90,179**	**99,871**	**107,160**	
6					
7	Vehicle Costs	4,626	3,111	3,084	
8	Employee Expenses	3,979	5,212	5,227	
9	Materials and Supplies	5,579	7,251	7,191	
10	Computer Costs	7,612	11,192	11,991	
11	Fees and Administration Costs	27,369	27,860	28,512	
12	Contractor Costs	58,251	60,112	60,052	
13	Facilities	11,717	13,973	14,318	
14	Recoveries & Revenue	(14,235)	(22,117)	(22,854)	
15					
16	**Non-Labour Costs**	**104,899**	**106,593**	**107,520**	
17					
18					
19	**Total Gross O&M Expenses**	**195,078**	**206,464**	**214,680**	
20					
21	Less: Vehicle Lease Reclass	(1,804)	-	-	
22	Less: Capitalized Overhead	(28,113)	(28,905)	(30,055)	
23					(X-Ref - Tab C-13, Schedule 4)
24	**Total O&M Expenses**	**$ 165,162**	**$ 177,559**	**$ 184,625**	(X-Ref - Tab C-13, Schedule 5)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW Schedule 29
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000)

Line No.	Particulars	Reference	PROJECTION 2009	FORECAST 2010	FORECAST 2011	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Distribution Supervision	100-11	$ 9,782	$ 10,331	$ 10,609	
2	Distribution Supervision Total	100-10	9,782	10,331	10,609	
3						
4	Operation Centre - Distribution	100-21	6,747	9,798	10,451	
5	Asset Management - Distribution	100-22	1,113	1,925	2,437	
6	Preventative Maintenance - Distribution	100-23	2,026	1,927	2,377	
7	Distribution Operations - General	100-24	4,720	5,096	5,512	
8	Emergency Management	100-25	6,582	5,240	5,488	
9	Distribution Operations Total	100-20	21,189	23,986	26,266	
10						
11	Distribution Corrective - Meters	100-31	1,176	1,433	1,524	
12	Distribution Corrective - Propane	100-32	5	5	5	
13	Distribution Corrective - Leak Repair	100-33	931	939	996	
14	Distribution Corrective - Stations	100-34	490	681	727	
15	Distribution Corrective - General	100-35	486	505	534	
16	Distribution Maintenance Total	100-30	3,089	3,562	3,785	
17						
18	**Distribution Total**	**100**	**34,060**	**37,879**	**40,660**	
19						
20	Transmission Supervision	200-11	2,448	3,079	3,161	
21	Transmission Supervision Total	200-10	2,448	3,079	3,161	
22						
23	Pipeline Operation	200-21	2,094	2,627	2,836	
24	Right of Way	200-22	1,407	1,282	1,345	
25	Compression	200-23	1,650	1,919	1,922	
26	Gas Control	200-24	2,264	2,896	3,105	
27	Transmission Pipeline Integrity Project (TPIP)	200-25	5,355	3,177	3,317	
28	Transmission Operations Total	200-20	12,771	11,902	12,525	
29						
30	Pipeline - Maintenance	200-31	167	189	194	
31	Compression - Maintenance	200-32	163	167	172	
32	TPIP - Maintenance	200-33	373	671	929	
33	Transmission Maintenance Total	200-30	702	1,027	1,295	
34						
35	**Transmission Total**	**200**	**15,921**	**16,008**	**16,980**	
36						
37	LNG Plant Operations	300-11	825	1,036	1,088	
38	LNG Plant Operations Total	300-10	825	1,036	1,088	
39	LNG Plant Maintenance	300-21	200	269	277	
40	LNG Plant Maintenance Total	300-20	200	269	277	
41						
42	**LNG Plant Total**	**300**	**1,025**	**1,305**	**1,365**	
43						
44	Measurement Operations	400-11	3,759	4,083	4,297	
45	Measurement Operations Total	400-10	3,759	4,083	4,297	
46						
47	Measurement Maintenance	400-21	1,804	2,208	2,334	
48	Measurement Maintenance Total	400-20	1,804	2,208	2,334	
49						
50	**Measurement Total**	**400**	**5,562**	**6,291**	**6,630**	

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 30

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000)

Line No.	Particulars	Reference	PROJECTION 2009	FORECAST 2010	FORECAST 2011	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Facilities Management	500-10	5,580	6,277	5,968	
2	Shops & Stores	500-20	3,699	4,018	4,152	
3	Operations Engineering	500-30	6,368	8,121	8,679	
4	Property Services	500-40	988	1,174	1,307	
5	System Integrity	500-50	2,040	2,393	2,492	
6	Environmental Health & Safety	500-60	1,490	2,352	2,504	
7	Operations Governance	500-70	1,515	1,692	1,800	
8						
9	**General Operations Total**	**500**	**21,679**	**26,025**	**26,903**	
10						
11	Energy Efficiency	600-10	$ 1,624	$ -	$ -	
12	Marketing - Supervision	600-20	1,208	621	634	
13	Corporate & Marketing Communications	600-30	2,574	3,593	3,673	
14	Marketing Planning & Development	600-40	749	655	669	
15	**Marketing Total**	**600**	**6,156**	**4,868**	**4,976**	
16						
17	Customer Care - Supervision	700-10	1,089	2,069	2,126	
18	Customer Contact - ABSU contract	700-20	47,127	48,470	49,422	
19	Bad Debt Management and Administration	700-30	6,112	5,874	6,018	
20	Customer Management & Sales	700-40	3,349	3,949	4,176	
21	**Customer Care Total**	**700**	**57,677**	**60,361**	**61,742**	
22						
23	Business & IT Services - Supervision	800-10	1,419	1,239	1,268	
24	Application Management	800-20	9,313	12,682	13,512	
25	Infrastructure Management	800-30	5,208	6,461	6,775	
26	Procurement Services	800-40	736	824	874	
27	**Business & IT Services Total**	**800**	**16,675**	**21,205**	**22,428**	
28						
29	Administration & General	900-11	3,229	(207)	(1,185)	
30	Insurance	900-12	4,725	4,410	4,631	
31	Finance and Regulatory Affairs	900-13	9,585	9,641	9,994	
32	Shared Services Agreement	900-14	3,541	2,116	1,899	
33	Corporate Administration Total	900-10	21,080	15,960	15,339	
34	Forecasting	900-20	1,022	1,632	1,672	
35	Public Affairs	900-30	1,375	1,731	1,762	
36	Business Development	900-40	1,416	3,123	3,183	
37	Human Resources	900-50	5,440	6,687	6,930	
38	Other Post Employment Benefits (OPEB)	900-60	5,991	3,389	4,111	
39	**Administration & General Total**	**900**	**36,324**	**32,522**	**32,996**	
40						
41	**Total Gross O&M Expenses**		**195,078**	**206,464**	**214,680**	
42						
43	Less: Vehicle Lease Reclass		(1,804)	-	-	
44	Less: Capitalized Overhead		(28,113)	(28,905)	(30,055)	
45						(X-Ref - Tab C-13, Schedule 4)
46	**Total O&M Expenses**		**$ 165,162**	**$ 177,559**	**$ 184,625**	(X-Ref - Tab C-13, Schedule 5)

* Note : Line 29 "Administration and General" expenses show a reduction of $1.0 million. The allocation of this $1.0 million reduction will be determined at a later date.

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 31

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Total Expenses	2010 Revised Revenue, Total Expenses	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$16,187	$16,187	$16,187	$0	
4						
5	General, School and Other	33,006	33,006	33,006	-	
6						(X-Ref - Tab C-13, Schedule 4)
7	Total	$49,193	$49,193	$49,193	$0	(X-Ref - Tab C-13, Schedule 12)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 32

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Total Expenses	2011 Revised Revenue, Total Expenses	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$16,067	$16,067	$16,067	$0	
4						
5	General, School and Other	34,144	34,144	34,144	-	
6						(X-Ref - Tab C-13, Schedule 5)
7	Total	$50,211	$50,211	$50,211	$0	(X-Ref - Tab C-13, Schedule 13)

TERASEN GAS INC. — Nov 5, 2009 NSP Agreement — Section C, Tab 13, Schedule 33

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation Provision**				
2					
3	Total Depreciation Expense	$113,009	$98,312	($14,697)	- Tab C-13, Schedule 49
4					
5	Less: Amortization of Contributions in Aid of Construction	(6,849)	(6,850)	(1)	- Tab C-13, Schedule 52
6		106,160	91,462	(14,698)	
7					
8	Add: Removal Cost Provision	-	8,038	8,038	(X-Ref - Tab C-13, Schedule 4)
9					
10		106,160	99,500	($6,660)	
11			(X-Ref - Tab C-13, Schedule 37)		
12	**Amortization Expense**				
13					
14	Amortization of Deferred Charges	($2,364)	($2,569)	($205)	- Tab C-13, Schedule 54
15					
16		(2,364)	(2,569)	(205)	
17					(X-Ref - Tab C-13, Schedule 4)
18	TOTAL	$103,796	96,931	($6,865)	(X-Ref - Tab C-13, Schedule 12)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 34

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation Provision**				
2					
3	Total Depreciation Expense	$115,696	$100,534	($15,162)	- Tab C-13, Schedule 51
4					
5	Less: Amortization of Contributions in Aid of Construction	(6,674)	(6,677)	(3)	- Tab C-13, Schedule 53
6		109,022	93,857	(15,165)	
7					
8	Add: Removal Cost Provision	-	11,290	11,290	(X-Ref - Tab C-13, Schedule 5)
9					
10		109,022	105,147	(15,165)	
11			(X-Ref - Tab C-13, Schedule 38)		
12	**Amortization Expense**				
13					
14	Amortization of Deferred Charges	$1,474	($5,269)	($6,743)	- Tab C-13, Schedule 55
15					
16		1,474	(5,269)	(6,743)	
17					(X-Ref - Tab C-13, Schedule 5)
18	TOTAL	$110,496	$99,878	($21,908)	(X-Ref - Tab C-13, Schedule 13)

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
Tab 13
Schedule 35

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing Rates	2010 ----Revised Rates----- Revised Revenue	2010 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$185,254	$184,217	$0	$184,217	($1,037)	- Tab C-13, Schedule 4
3	Deduct - Interest on Debt	(110,056)	(109,062)	-	(109,062)	994	- Tab C-13, Schedule 10
4	Add- Non-Tax Ded. Expense (Net)	(1,864)	(2,069)	-	(2,069)	(205)	- Tab C-13, Schedule 37
5	Accounting Income After Tax	73,334	73,086	-	73,086	(248)	
6	Add (Deduct) - Timing Differences	5,999	(4,958)	-	(4,958)	(10,957)	- Tab C-13, Schedule 37
7	Taxable Income After Tax	79,333	68,128	-	68,128	(11,205)	
8	Taxable Income Adj - SCP Landscaping Deduction	-	(7,834)	-	(7,834)	(7,834)	
9	Taxable Income Adj - Tax on SCP Landscaping	-	2,233	-	2,233	2,233	
10	Adjusted Taxable Income After Tax	$79,333	$62,527	$0	$62,527	($16,806)	
11							
12		28.500%	28.500%	28.500%	28.500%	0.000%	
13	1 - Current Income Tax Rate	71.500%	71.500%	71.500%	71.500%	0.000%	
14							
15	Taxable Income	110,955	$87,450	$0	$87,450	($23,505)	
16							(X-Ref - Tab C-13, Schedule 4)
17	**Total Income Tax**	$31,622	$24,923	$0	$24,923	($6,699)	(X-Ref - Tab C-13, Schedule 12)

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
Tab 13
Schedule 36

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing Rates	2011 ----Revised Rates----- Revised Revenue	2011 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$193,132	$184,295	$8,639	$192,934	($198)	- Tab C-13, Schedule 5
3	Deduct - Interest on Debt	(115,430)	(114,982)	-	(114,982)	448	- Tab C-13, Schedule 11
4	Add- Non-Tax Ded. Expense (Net)	1,974	(4,769)	-	(4,769)	(6,743)	- Tab C-13, Schedule 38
5	Accounting Income After Tax	79,676	64,544	8,639	73,183	(6,493)	
6	Add (Deduct) - Timing Differences	8,118	(5,053)	-	(5,053)	(13,171)	- Tab C-13, Schedule 38
7	Taxable Income After Tax	87,794	59,491	8,639	68,130	(19,664)	
8	Taxable Income Adjustment	-	-	-	-	-	
9	Taxable Income Adjustment	-	-	-	-	-	
10	Adjusted Taxable Income After Tax	$87,794	$59,491	$8,639	$68,130	($19,664)	
11							
12		26.500%	26.500%	26.500%	26.500%	0.000%	
13	1 - Current Income Tax Rate	73.500%	73.500%	73.500%	73.500%	0.000%	
14							
15	Taxable Income	119,448	$80,940	$11,754	$92,694	($26,754)	
16							(X-Ref - Tab C-13, Schedule 5)
17	**Total Income Tax**	$31,654	$21,449	$3,115	$24,564	($1,767)	(X-Ref - Tab C-13, Schedule 13)

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C, Tab 13, Schedule 37

NON-TAX DEDUCTIBLE EXPENSES (NET) AND TIMING DIFFERENCE ADJUSTMENTS
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**ITEMS OF A PERMANENT NATURE INCREASING TAXABLE INCOME**				
2					
3	Amortization of Deferred Charges	($2,364)	($2,569)	($205)	- Tab C-13, Schedule 54
4					
5	Non-tax Deductible Expenses	500	500	-	
6					
7	Total Permanent Differences	($1,864)	($2,069)	($205)	(X-Ref - Tab C-13, Schedule 35)
8					(X-Ref - Tab C-13, Schedule 6)
9	**TIMING DIFFERENCE ADJUSTMENTS**				
10					
11	Addbacks:				
12	Depreciation & Removal Cost Provision	$106,160	99,500	($6,660)	- Tab C-13, Schedule 33
13	Amortization of Debt Issue Expenses	721	721	-	
14	Vehicle Capital Lease: Interest & Capitialized Depreciation	1,597	1,597	-	
15	Pension Expense	4,779	4,779	-	
16	OPEB Expense	5,320	5,320	-	
17	2010 Revenue Surplus (Net of Tax)	-	6,537	6,537	
18					
19	Deductions:				
20	Capital Cost Allowance	(98,544)	(96,990)	1,554	- Tab C-13, Schedule 39
21	Cumulative Eligible Capital Allowance	(1,001)	(1,001)	-	
22	Debt Issue Costs	(1,206)	(1,206)	-	
23	Vehicle Lease Payment	(3,149)	(3,149)	-	
24	Pension Contributions	(7,115)	(7,115)	-	
25	OPEB Contributions	(503)	(503)	-	
26	Overheads Capitalized Expensed for Tax Purposes	-	(12,388)	(12,388)	
27	Overhead Capitalization Rate Change	-	-	-	
28	CCA Rate Change of 2007 & 2008	-	-	-	
29	Long Term Compensation	-	-	-	
30	Discounts on Debt Issue and Other	-	-	-	
31	Major Inspection Costs	(1,060)	(1,060)	-	
32					
33	Total Timing Differences	$5,999	($4,958)	($10,957)	(X-Ref - Tab C-13, Schedule 35)
					(X-Ref - Tab C-13, Schedule 6)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 38

NON-TAX DEDUCTIBLE EXPENSES (NET) AND TIMING DIFFERENCE ADJUSTMENTS
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**ITEMS OF A PERMANENT NATURE INCREASING TAXABLE INCOME**				
2					
3	Amortization of Deferred Charges	$1,474	($5,269)	($6,743)	- Tab C-13, Schedule 55
4					
5	Non-tax Deductible Expenses	500	500	-	
6					
7	Total Permanent Differences	$1,974	($4,769)	($6,743)	(X-Ref - Tab C-13, Schedule 36)
8					(X-Ref - Tab C-13, Schedule 6)
9	**TIMING DIFFERENCE ADJUSTMENTS**				
10					
11	Addbacks:				
12	Depreciation & Removal Cost Provision	$109,022	105,147	($3,875)	- Tab C-13, Schedule 34
13	Amortization of Debt Issue Expenses	721	721	-	
14	Vehicle Capital Lease: Interest & Capitialized Depreciation	2,029	2,029	-	
15	Pension Expense	5,704	5,704	-	
16	OPEB Expense	5,297	5,297	-	
17	2010 Revenue Surplus	-	-	-	
18					
19	Deductions:				
20	Capital Cost Allowance	(100,844)	(97,259)	3,585	- Tab C-13, Schedule 40
21	Cumulative Eligible Capital Allowance	(937)	(937)	-	
22	Debt Issue Costs	(1,003)	(1,003)	-	
23	Vehicle Lease Payment	(3,736)	(3,736)	-	
24	Pension Contributions	(7,322)	(7,322)	-	
25	OPEB Contributions	(503)	(503)	-	
26	Overheads Capitalized Expensed for Tax Purposes	-	(12,881)	(12,881)	
27	Overhead Capitalization Rate Change	-	-	-	
28	CCA Rate Change of 2007 & 2008	-	-	-	
29	Long Term Compensation	-	-	-	
30	Discounts on Debt Issue and Other	-	-	-	
31	Major Inspection Costs	(310)	(310)	-	
32					
33	Total Timing Differences	$8,118	($5,053)	($13,171)	(X-Ref - Tab C-13, Schedule 36)
					(X-Ref - Tab C-13, Schedule 7)

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Class	CCA Rate %	12/31/2009 UCC Balance	Adjustments	2010 Net Additions	2010 CCA	12/31/2010 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$1,190,923	($7,834)	$371	($47,331)	$1,136,129
2	1.3	6%	8,120	-	2,755	(570)	10,305
3	2	6%	164,165	-	-	(9,850)	154,315
4	3	5%	2,826	-	-	(141)	2,685
5	6	10%	206	-	-	(21)	185
6	7	15%	3,824	-	2,188	(738)	5,274
7	8	20%	15,184	-	2,441	(3,281)	14,344
8	10	30%	3,135	-	1,629	(1,185)	3,579
9	12	100%	-	3,087	11,604	(8,889)	5,802
10	13	Manual	2,682	-	167	(890)	1,959
11	14	Manual	2	-	-	(2)	-
12	17	8%	223	-	-	(18)	205
13	38	30%	225	-	30	(72)	183
14	39	25%	-	-	-	-	-
15	45	45%	891	-	-	(401)	490
16	47	8%	4,798	-	451	(402)	4,847
17	49	8%	65,970	-	12,903	(5,794)	73,079
18	50 / 52	55% / 100%	1,432	-	4,489	(5,276)	645
19	51	6%	168,386	-	67,541	(12,129)	223,798
20							
21		Total	$1,632,992	($4,747)	$106,569	($96,990)	$1,637,824
22						(X-Ref - Tab C-13, Schedule 37)	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Class	CCA Rate %	12/31/2010 UCC Balance	Adjustments	2011 Net Additions	2011 CCA	12/31/2011 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$1,136,129	$0	$0	($45,445)	$1,090,684
2	1.3	6%	10,305	-	3,590	(726)	13,169
3	2	6%	154,315	-	-	(9,259)	145,056
4	3	5%	2,685	-	-	(134)	2,551
5	6	10%	185	-	-	(19)	166
6	7	15%	5,274	-	1,617	(912)	5,979
7	8	20%	14,344	-	2,214	(3,090)	13,468
8	10	30%	3,579	-	1,607	(1,315)	3,871
9	12	100%	5,802	-	11,000	(11,302)	5,500
10	13	Manual	1,959	-	51	(883)	1,127
11	14	Manual	-	-	-	-	-
12	17	8%	205	-	-	(17)	188
13	38	30%	183	-	30	(59)	154
14	39	25%	-	-	-	-	-
15	45	45%	490	-	-	(220)	270
16	47	8%	4,847	-	1,651	(454)	6,044
17	49	8%	73,079	-	6,024	(6,087)	73,016
18	50 / 52	55% / 100%	645	-	5,000	(1,729)	3,916
19	51	6%	223,798	-	72,667	(15,608)	280,857
20							
21		Total	$1,637,824	$0	$105,451	($97,259)	$1,646,016
22						(X-Ref - Tab C-13, Schedule 38)	

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 41

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing 2009 Rates	2010 Adjustments	2010 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,317,590	$3,315,365	$0	$3,315,365	($2,225)	- Tab C-13, Schedule 45
2	Adjustment - CPCNs	-				-	- Tab C-13, Schedule 43
3	Gas Plant in Service, Ending	3,449,336	3,453,394	-	3,453,394	4,058	- Tab C-13, Schedule 45
4							
5	Accumulated Depreciation Beginning - Plant	($779,187)	($780,174)	$0	($780,174)	($987)	- Tab C-13, Schedule 49
6	Accumulated Depreciation Ending - Plant	(840,835)	(835,365)	-	(835,365)	5,470	- Tab C-13, Schedule 49
7							
8	CIAC, Beginning	($176,845)	($176,845)	$0	($176,845)	$0	- Tab C-13, Schedule 52
9	CIAC, Ending	(183,817)	(183,885)	-	(183,885)	(68)	- Tab C-13, Schedule 52
10							
11	Accumulated Amortization Beginning - CIAC	$44,146	$44,146	$0	$44,146	$0	- Tab C-13, Schedule 52
12	Accumulated Amortization Ending - CIAC	47,061	47,062	-	47,062	1	- Tab C-13, Schedule 52
13							
14	Net Plant in Service, Mid-Year	$2,438,725	$2,441,849	$0	$2,441,849	$3,125	
15							
16	Adjustment to 13-Month Average	13,537	13,537	-	13,537	-	
17	Work in Progress, No AFUDC	15,627	15,627	-	15,627	-	
18	Unamortized Deferred Charges	(27,015)	(30,797)	-	(30,797)	(3,782)	- Tab C-13, Schedule 54
19	Cash Working Capital	(6,778)	(7,563)	-	(7,563)	(785)	- Tab C-13, Schedule 56
20	Other Working Capital (incl. Construction Advances)	103,439	103,439	-	103,439	-	- Tab C-13, Schedule 56
21	Future Income Taxes Regulatory Asset	284,455	284,455	-	284,455	-	- Tab C-13, Schedule 61
22	Future Income Taxes Regulatory Liability	(284,455)	(284,455)	-	(284,455)	-	- Tab C-13, Schedule 61
23	LILO Benefit	(1,648)	(1,648)	-	(1,648)	-	
24	**Utility Rate Base**	$2,535,887	$2,534,444	$0	$2,534,444	($1,442)	(X-Ref - Tab C-13, Schedule 10)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 42

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing 2009 Rates	2011 Adjustments	2011 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,449,336	$3,453,394	$0	$3,453,394	$4,058	- Tab C-13, Schedule 47
2	Adjustment - CPCNs	-				-	
3	Gas Plant in Service, Ending	3,535,828	3,538,378	-	3,538,378	2,550	- Tab C-13, Schedule 47
4							
5	Accumulated Depreciation Beginning - Plant	($840,835)	($835,365)	$0	($835,365)	$5,470	- Tab C-13, Schedule 51
6	Accumulated Depreciation Ending - Plant	(899,386)	(885,651)	-	(885,651)	13,735	- Tab C-13, Schedule 51
7							
8	CIAC, Beginning	($183,817)	($183,885)	$0	($183,885)	($68)	- Tab C-13, Schedule 53
9	CIAC, Ending	(194,646)	(194,753)	-	(194,753)	(107)	- Tab C-13, Schedule 53
10							
11	Accumulated Amortization Beginning - CIAC	$47,061	$47,062	$0	$47,062	$1	- Tab C-13, Schedule 53
12	Accumulated Amortization Ending - CIAC	50,241	50,245	-	50,245	4	- Tab C-13, Schedule 53
13							
14	Net Plant in Service, Mid-Year	$2,481,891	$2,494,713	$0	$2,494,713	$12,822	
15							
16	Adjustment to 13-Month Average	0	-	-	-	-	
17	Work in Progress, No AFUDC	15,627	15,627	-	15,627	-	
18	Unamortized Deferred Charges	10,347	6,770	-	6,770	(3,577)	- Tab C-13, Schedule 55
19	Cash Working Capital	(6,133)	(6,953)	6	(6,947)	(814)	- Tab C-13, Schedule 57
20	Other Working Capital (incl. Construction Advances)	120,091	120,091	-	120,091	-	- Tab C-13, Schedule 57
21	Future Income Taxes Regulatory Asset	292,155	292,155	-	292,155	-	- Tab C-13, Schedule 61
22	Future Income Taxes Regulatory Liability	(292,155)	(292,155)	-	(292,155)	-	- Tab C-13, Schedule 61
23	LILO Benefit	(1,482)	(1,482)	-	(1,482)	-	
24	**Utility Rate Base**	$2,620,341	$2,628,766	$6	$2,628,772	$8,431	(X-Ref - Tab C-13, Schedule 11)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 43

CAPITAL EXPENDITURES AND PLANT ADDITIONS
FOR THE YEARS ENDING DECEMBER 31, 2009 - 2011
($000)

Line No.	Particulars	Projected 2009	Forecast 2010	Forecast 2011	Reference
	(1)	(2)	(3)	(4)	(5)
1	**CAPITAL EXPENDITURES**				
2					
3	Regular Capital Expenditures				
4	Regular Capital Expenditures	85,425	93,511	93,597	
5	Gateway Project *	11,174	6,750	10,433	
6					
7	Total Regular Capital Expenditures	$ 96,599	$ 100,261	$ 104,030	
8					
9	Special Projects - CPCN's				
10	Vancouver LP Replacement	250	-	-	
11	Fraser River SBSA Rehabilitation	25,000	520	-	
12	Okanagan Reinforcement Project	500	500	500	
13	CCE CPCN	7,476	49,662	57,761	
14	Kootenay River Crossing	-	2,000	4,000	
15	Huntingdon Bypass	-	200	12,000	
16		0.00	0	0	
17	Total CPCN's	$ 33,226	$ 52,882	$ 74,261	
18					
19					
20	TOTAL CAPITAL EXPENDITURES	$ 129,825	$ 153,143	$ 178,291	
21					
22					
23	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**				
24					
25	Regular Capital				
26	Regular Capital Expenditures	96,599	100,260	104,030	
27	Add - Opening WIP	18,760	26,434	24,877	
28	Less - Opening WIP Adjustment	-	-	-	
29	Less - Closing WIP	(26,434)	(24,877)	(25,706)	
30	Capital Spares Inventory Reclassification	8,593	-	-	
31	Capital Vehicle Lease Addition	-	3,869	2,735	
32	Add - AFUDC	267	230	241	- Tab C-13, Schedule 45
33	Add - Overhead Capitalized	28,113	28,905	30,055	- Tab C-13, Schedule 47
34					
35	TOTAL REGULAR CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	$ 125,898	$ 134,821	$ 136,232	
36					
37	Special Projects - CPCN's				
38	CPCN Expenditures	33,226	52,882	74,261	
39	Add - Opening WIP	14,676	35,291	62,672	
40	Less - Closing WIP	(35,291)	(62,672)	(143,095)	
41	Less: Vancouver LP Removal costs (added to Accumulated Depreciation)	(394)	-	-	
42	Add - AFUDC	662	2,102	6,162	
43					- Tab C-13, Schedule 45
44	TOTAL CPCN ADDITIONS TO OPENING GAS PLANT IN SERVICE	$ 12,879	$ 27,603	-$ 0	- Tab C-13, Schedule 47
45		(X-Ref - Tab C-13, Schedule 41)			
46	TOTAL PLANT ADDITIONS	$ 138,777	$ 162,424	$ 136,232	
47					
48	Capital Vehicle Lease Opening Adjustment	-	26,103	-	- Tab C-13, Schedule 45
49					
50	TOTAL PLANT ADDITIONS and OPENING ADJUSTMENTS	$ 138,777	$ 188,527	$ 136,232	
51					
52					
53	* Spending associated with the Gateway Project is expected to be fully recovered via a contribution in aid of construction.				

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 44

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Balance 12/31/2009	CPCN'S	2010 Additions	2010 AFUDC	Retirements	Transfers/ Recovery	Balance 12/31/2010	Mid-year GPIS for Depreciation	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$0	$0	$0	$0	$0	$0	$0	$0	
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	109	109	
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	777	777	
5	178-00 Organization Expense	728	-	-	-	-	-	728	728	
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	
7	401-00 Franchise and Consents	99	-	-	-	-	-	99	99	
8	402-00 Utility Plant Acquisition Adjustment	63	-	-	-	-	-	63	63	
9	402-00 Other Intangible Plant	688	-	-	-	-	-	688	688	
10	461-00 Land Rights - Transmission	43,782	-	121	-	-	-	43,903	43,843	
11	461-10 Land Rights - Transmission - Byron Creek	16	-	-	-	-	-	16	16	
12	471-00 Land Rights - Distribution	1,065	-	-	-	-	-	1,065	1,065	
13	471-10 Land Rights - Distribution - Byron Creek	-	-	-	-	-	-	-	-	
14	402-01 Application Software - 12.5%	55,628	-	11,604	66	(8,954)	-	58,344	56,986	
15	402-02 Application Software - 20%	8,051	-	-	-	(1,847)	-	6,204	7,128	
16	TOTAL INTANGIBLE PLANT	111,006	-	11,725	66	(10,801)	-	111,996	111,501	
17										
18	**MANUFACTURED GAS / LOCAL STORAGE**									
19	430 Manufact'd Gas - Land	31	-	-	-	-	-	31	31	
20	432 Manufact'd Gas - Struct. & Improvements	475	-	-	-	-	-	475	475	
21	433 Manufact'd Gas - Equipment	425	-	425	-	-	-	850	638	
22	434 Manufact'd Gas - Gas Holders	663	-	-	-	-	-	663	663	
23	436 Manufact'd Gas - Compressor Equipment	53	-	-	-	-	-	53	53	
24	437 Manufact'd Gas - Measuring & Regulating Equipment	309	-	-	-	-	-	309	309	
25	440/441 Land in Fee Simple	928	-	-	-	-	-	928	928	
26	442 Structures & Improvements	4,885	-	-	-	-	-	4,885	4,885	
27	443 Gas Holders - Storage	16,655	-	519	4	-	-	17,178	16,917	
28	446 Compressor Equipment	-	-	-	-	-	-	-	-	
29	447 Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	
30	448 Purification Equipment	-	-	-	-	-	-	-	-	
31	449 Local Storage Equipment	23,410	-	-	-	-	-	23,410	23,410	
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	47,834	-	944	4	-	-	48,782	48,308	
33										
34	**TRANSMISSION PLANT**									
35	460-00 Land in Fee Simple	7,408	-	-	-	-	-	7,408	7,408	
36	462-00 Compressor Structures	14,690	-	-	-	-	-	14,690	14,690	
37	463-00 Measuring Structures	4,949	-	-	-	-	-	4,949	4,949	
38	464-00 Other Structures & Improvements	5,960	-	-	-	-	-	5,960	5,960	
39	465-00 Mains	736,398	27,349	21,172	79	(1,063)	(1,985)	781,950	772,849	*
40	465-00 Mains - Inspection	-	-	1,505	6	-	1,985	3,496	1,748	
41	465-10 Mains - Byron Creek	932	-	-	-	-	-	932	932	
42	466-00 Compressor Equipment	111,042	-	1,769	7	-	-	112,818	111,930	
43	466-00 Compressor Equipment - Overhaul	-	-	-	-	-	-	-	-	
44	467-00 Measuring & Regulating Equipment	29,409	-	-	-	-	-	29,409	29,409	
45	467-10 Telemetering	8,494	-	106	-	-	-	8,600	8,547	
46	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	39	39	
47	468-00 Communication Structures & Equipment	346	-	-	-	-	-	346	346	
48	469-00 Other Transmission Equipment	-	-	-	-	-	-	-	-	
49	TOTAL TRANSMISSION PLANT	919,667	27,349	24,552	92	(1,063)	-	970,597	958,807	
50										
51	* Adjusted for full year impact of 2009 Fraser River SBSA CPCN.									

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C Tab 13 Schedule 45

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Balance 12/31/2009	CPCN'S	2010 Additions	2010 AFUDC	Retirements	Transfers/ Recovery	Balance 12/31/2010	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**DISTRIBUTION PLANT**								
2	470-00 Land in Fee Simple	$3,418	$0	$0	$0	$0	$0	$3,418	$3,418
3	472-00 Structures & Improvements	14,697	-	-	-	-	-	14,697	14,697
4	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	107	107
5	473-00 Services	640,145	254	31,160	-	(7,790)	-	663,769	652,084 **
6	473-00 Services - LILO	43,229	-	-	-	-	-	43,229	43,229
7	474-00 House Regulators & Meter Installations	134,325	-	13,786	3	(11,032)	-	137,082	135,704
8	474-00 House Regulators & Meter Installations - LILO	16,070	-	-	-	-	-	16,070	16,070
9	475-00 Mains	844,063	-	21,883	31	(2,192)	-	863,785	853,924
10	475-00 Mains - LILO	39,704	-	-	-	-	-	39,704	39,704
11	476-00 Compressor Equipment	571	-	-	-	-	-	571	571
12	477-00 Measuring & Regulating Equipment	82,546	-	5,423	21	(817)	-	87,173	84,860
13	477-00 Telemetering	5,916	-	256	1	(13)	-	6,160	6,038
14	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	163	163
15	478-10 Meters	184,767	-	9,883	-	(7,907)	-	186,743	185,755
16	478-11 Meters - LILO	10,027	-	-	-	-	-	10,027	10,027
17	478-20 Instruments	11,251	-	-	-	-	-	11,251	11,251
18	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-
19	TOTAL DISTRIBUTION PLANT	2,030,999	254	82,391	56	(29,751)	-	2,083,949	2,057,601
20									
21	**GENERAL PLANT & EQUIPMENT**								
22	480-00 Land in Fee Simple	21,905	-	126	-	-	-	22,031	21,968
23	481-00 Land Rights	-	-	-	-	-	-	-	-
24	482-00 Structures & Improvements	-	-	-	-	-	-	-	-
25	- Frame Buildings	5,286	-	-	-	-	-	5,286	5,286
26	- Masonry Buildings	83,527	-	2,228	-	-	-	85,755	84,641
27	- Leasehold Improvement	473	-	167	1	-	-	641	557
28	Office Equipment & Furniture	-	-	-	-	-	-	-	-
29	483-30 GP Office Equipment	4,480	-	87	-	(90)	-	4,477	4,479
30	483-40 GP Furniture	19,730	-	509	1	(5)	-	20,235	19,983
31	483-10 GP Computer Hardware	18,220	-	4,489	10	(6,245)	-	16,474	17,347
32	483-20 GP Computer Software	853	-	-	-	(20)	-	833	843
33	483-21 GP Computer Software	-	-	-	-	-	-	-	-
34	484-00 Transportation Equipment	2,279	-	1,629	-	-	-	3,908	3,094
35	484-00 Vehicles - Leased	-	-	3,869	-	(2,321)	26,103	27,651	26,877
36	485-10 Heavy Work Equipment	209	-	-	-	-	-	209	209
37	485-20 Heavy Mobile Equipment	561	-	30	-	-	-	591	576
38	486-00 Small Tools & Equipment	32,177	-	1,137	-	-	-	33,314	32,746
39	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	24	24
40	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-
41	488-00 Communications Equipment	-	-	-	-	-	-	-	-
42	- Telephone	11,239	-	504	-	(202)	-	11,541	11,390
43	- Radio	4,896	-	204	-	-	-	5,100	4,998
44	489-00 Other General Equipment	-	-	-	-	-	-	-	-
45	TOTAL GENERAL PLANT	205,859	-	14,979	12	(8,883)	26,103	238,070	235,016
46									
47	**UNCLASSIFIED PLANT**								
48	499 Plant Suspense	-	-	-	-	-	-	-	-
49	TOTAL UNCLASSIFIED PLANT	-	-	-	-	-	-	-	-
53									
54	TOTAL CAPITAL	$3,315,365	$27,603	$134,591	$230	($50,498)	$26,103	$3,453,394	$3,411,233
55		(X-Ref - Tab C-13, Schedule 8)	(X-Ref - Tab C-13, Schedule 43)					(X-Ref - Tab C-13, Schedule 49)	
56	** Adjusted for full year impact of 2009 Vancouver LP Replacement CPCN.							(X-Ref - Tab C-13, Schedule 8)	

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 46

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciatior
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**								
2	117-00 Utility Plant Acquisition Adjustment	$0	$0	$0	$0	$0	$0	$0	$0
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	109	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	777	777
5	178-00 Organization Expense	728	-	-	-	-	-	728	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	-	-	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	63	-	-	-	-	-	63	63
9	402-00 Other Intangible Plant	688	-	-	-	-	-	688	688
10	461-00 Land Rights - Transmission	43,903	-	124	-	-	-	44,027	43,965
11	461-10 Land Rights - Transmission - Byron Creek	16	-	-	-	-	-	16	16
12	471-00 Land Rights - Distribution	1,065	-	-	-	-	-	1,065	1,065
13	471-10 Land Rights - Distribution - Byron Creek	-	-	-	-	-	-	-	-
14	402-01 Application Software - 12.5%	58,344	-	11,000	66	(10,840)	-	58,570	58,457
15	402-02 Application Software - 20%	6,204	-	-	-	(1,147)	-	5,057	5,631
16	TOTAL INTANGIBLE PLANT	111,996	-	11,124	66	(11,987)	-	111,199	111,598
17									
18	**MANUFACTURED GAS / LOCAL STORAGE**								
19	430 Manufact'd Gas - Land	31	-	-	-	-	-	31	31
20	432 Manufact'd Gas - Struct. & Improvements	475	-	-	-	-	-	475	475
21	433 Manufact'd Gas - Equipment	850	-	-	-	-	-	850	850
22	434 Manufact'd Gas - Gas Holders	663	-	-	-	-	-	663	663
23	436 Manufact'd Gas - Compressor Equipment	53	-	-	-	-	-	53	53
24	437 Manufact'd Gas - Measuring & Regulating Equipment	309	-	-	-	-	-	309	309
25	440/441 Land in Fee Simple	928	-	-	-	-	-	928	928
26	442 Structures & Improvements	4,885	-	-	-	-	-	4,885	4,885
27	443 Gas Holders - Storage	17,178	-	1,894	17	-	-	19,089	18,134
28	446 Compressor Equipment	-	-	-	-	-	-	-	-
29	447 Measuring & Regulating Equipment	-	-	-	-	-	-	-	-
30	448 Purification Equipment	-	-	-	-	-	-	-	-
31	449 Local Storage Equipment	23,410	-	-	-	-	-	23,410	23,410
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	48,782	-	1,894	17	-	-	50,693	49,738
33									
34	**TRANSMISSION PLANT**								
35	460-00 Land in Fee Simple	7,408	-	-	-	-	-	7,408	7,408
36	462-00 Compressor Structures	14,690	-	-	-	-	-	14,690	14,690
37	463-00 Measuring Structures	4,949	-	-	-	-	-	4,949	4,949
38	464-00 Other Structures & Improvements	5,960	-	-	-	-	-	5,960	5,960
39	465-00 Mains	781,950	-	18,761	78	(942)	-	799,847	790,899
40	465-00 Mains - Inspection	3,496	-	444	2	-	-	3,942	3,719
41	465-10 Mains - Byron Creek	932	-	-	-	-	-	932	932
42	466-00 Compressor Equipment	112,818	-	1,851	8	-	-	114,677	113,748
43	466-00 Compressor Equipment - Overhaul	-	-	-	-	-	-	-	-
44	467-00 Measuring & Regulating Equipment	29,409	-	-	-	-	-	29,409	29,409
45	467-10 Telemetering	8,600	-	71	-	-	-	8,671	8,636
46	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	39	39
47	468-00 Communication Structures & Equipment	346	-	-	-	-	-	346	346
48	469-00 Other Transmission Equipment	-	-	-	-	-	-	-	-
49	TOTAL TRANSMISSION PLANT	970,597	-	21,127	88	(942)	-	990,870	980,734

TERASEN GAS INC. — Nov 5, 2009 NSP Agreement — Section C, Tab 13, Schedule 47

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciatior
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**DISTRIBUTION PLANT**								
2	470-00 Land in Fee Simple	$3,418	$0	$0	$0	$0	$0	$3,418	$3,418
3	472-00 Structures & Improvements	14,697	-	-	-	-	-	14,697	14,697
4	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	107	107
5	473-00 Services	663,769	-	33,776	-	(8,444)	-	689,101	676,435
6	473-00 Services - LILO	43,229	-	-	-	-	-	43,229	43,229
7	474-00 House Regulators & Meter Installations	137,082	-	14,821	3	(11,859)	-	140,047	138,565
8	474-00 House Regulators & Meter Installations - LILO	16,070	-	-	-	-	-	16,070	16,070
9	475-00 Mains	863,785	-	22,408	31	(2,244)	-	883,980	873,883
10	475-00 Mains - LILO	39,704	-	-	-	-	-	39,704	39,704
11	476-00 Compressor Equipment	571	-	-	-	-	-	571	571
12	477-00 Measuring & Regulating Equipment	87,173	-	5,560	24	(838)	-	91,919	89,546
13	477-00 Telemetering	6,160	-	258	1	(13)	-	6,406	6,283
14	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	163	163
15	478-10 Meters	186,743	-	10,391	-	(8,313)	-	188,821	187,782
16	478-11 Meters - LILO	10,027	-	-	-	-	-	10,027	10,027
17	478-20 Instruments	11,251	-	-	-	-	-	11,251	11,251
18	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-
19	TOTAL DISTRIBUTION PLANT	2,083,949	-	87,214	59	(31,711)	-	2,139,511	2,111,730
20									
21	**GENERAL PLANT & EQUIPMENT**								
22	480-00 Land in Fee Simple	22,031	-	129	-	-	-	22,160	22,096
23	481-00 Land Rights	-	-	-	-	-	-	-	-
24	482-00 Structures & Improvements	-	-	-	-	-	-	-	-
25	- Frame Buildings	5,286	-	-	-	-	-	5,286	5,286
26	- Masonry Buildings	85,755	-	2,869	-	-	-	88,624	87,190
27	- Leasehold Improvement	641	-	51	-	-	-	692	667
28	Office Equipment & Furniture	-	-	-	-	-	-	-	-
29	483-30 GP Office Equipment	4,477	-	60	-	(991)	-	3,546	4,012
30	483-40 GP Furniture	20,235	-	418	1	(1,230)	-	19,424	19,830
31	483-10 GP Computer Hardware	16,474	-	5,000	10	-	-	21,484	18,979
32	483-20 GP Computer Software	833	-	-	-	(198)	-	635	734
33	483-21 GP Computer Software	-	-	-	-	-	-	-	-
34	484-00 Transportation Equipment	3,908	-	1,607	-	-	-	5,515	4,712
35	484-00 Vehicles - Leased	27,651	-	2,735	-	(1,641)	-	28,745	28,198
36	485-10 Heavy Work Equipment	209	-	-	-	-	-	209	209
37	485-20 Heavy Mobile Equipment	591	-	30	-	-	-	621	606
38	486-00 Small Tools & Equipment	33,314	-	1,105	-	-	-	34,419	33,867
39	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	24	24
40	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-
41	488-00 Communications Equipment	-	-	-	-	-	-	-	-
42	- Telephone	11,541	-	464	-	(1,596)	-	10,409	10,975
43	- Radio	5,100	-	166	-	(954)	-	4,312	4,706
44	489-00 Other General Equipment	-	-	-	-	-	-	-	-
45	TOTAL GENERAL PLANT	238,070	-	14,634	11	(6,610)	-	246,105	242,088
46									
47	**UNCLASSIFIED PLANT**								
48	499 Plant Suspense	-	-	-	-	-	-	-	-
49	TOTAL UNCLASSIFIED PLANT	-	-	-	-	-	-	-	-
53									
54	TOTAL CAPITAL	$3,453,394	$0	$135,993	$241	($51,250)	$0	$3,538,378	$3,495,886
55		(X-Ref - Tab C-13, Schedule 9)	(X-Ref - Tab C-13, Schedule 43)					(X-Ref - Tab C-13, Schedule 51) (X-Ref - Tab C-13, Schedule 9)	

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 48

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2010 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Accumulated 12/31/2009	Accumulated 12/31/2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**								
2	117-00 Utility Plant Acquisition Adjustment	$0	1.00%	$0	$0	$0	$0	$0	$0
3	175-00 Unamortized Conversion Expense	109	1.00%	1	-	-	-	365	366
4	175-00 Unamortized Conversion Expense - Squamish	777	10.00%	78	-	-	-	156	234
5	178-00 Organization Expense	728	1.00%	7	-	-	-	369	376
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	19.76%	20	-	-	-	49	69
8	402-00 Utility Plant Acquisition Adjustment	63	23.66%	15	-	-	-	27	42
9	402-00 Other Intangible Plant	688	2.14%	15	-	-	-	151	166
10	461-00 Land Rights - Transmission	43,843	0.00%	-	-	-	-	651	651
11	461-10 Land Rights - Transmission - Byron Creek	16	0.00%	-	-	-	-	19	$19
12	471-00 Land Rights - Distribution	1,065	0.00%	-	-	-	-	2	2
13	471-10 Land Rights - Distribution - Byron Creek	-	0.00%	-	-	-	-	1	1
14	402-01 Application Software - 12.5%	56,986	12.50%	7,123	(4,264)	(8,954)	-	31,197	25,102
15	402-02 Application Software - 20%	7,128	20.00%	1,426	-	(1,847)	-	4,160	3,739
16	TOTAL INTANGIBLE PLANT	111,501		8,685	(4,264)	(10,801)	-	37,147	30,767
17									
18	**MANUFACTURED GAS / LOCAL STORAGE**								
19	430 Manufact'd Gas - Land	31	0.00%	-	-	-	-	-	-
20	432 Manufact'd Gas - Struct. & Improvements	475	3.28%	16	-	-	-	89	105
21	433 Manufact'd Gas - Equipment	638	6.30%	40	-	-	-	51	91
22	434 Manufact'd Gas - Gas Holders	663	3.90%	26	-	-	-	173	199
23	436 Manufact'd Gas - Compressor Equipment	53	4.96%	3	-	-	-	24	27
24	437 Manufact'd Gas - Measuring & Regulating Equipm	309	19.50%	60	-	-	-	152	212
25	440/441 Land in Fee Simple and Land Rights	928	0.00%	-	-	-	-	1	1
26	442 Structures & Improvements	4,885	3.65%	178	-	-	-	2,252	2,430
27	443 Gas Holders - Storage	16,917	2.18%	369	-	-	-	9,684	10,053
28	446 Compressor Equipment	-	0.00%	-	-	-	-	-	-
29	447 Measuring & Regulating Equipment	-	0.00%	-	-	-	-	-	-
30	448 Purification Equipment	-	0.00%	-	-	-	-	-	-
31	449 Local Storage Equipment	23,410	3.36%	787	-	-	-	8,336	9,123
32	TOTAL MANUFACTURED GAS / LOCAL STORA(	48,308		1,479	-	-	-	20,762	22,241
33									
34	**TRANSMISSION PLANT**								
35	460-00 Land in Fee Simple	7,408	0.00%	-	-	-	-	401	401
36	462-00 Compressor Structures	14,690	3.84%	564	-	-	-	5,264	5,828
37	463-00 Measuring Structures	4,949	4.27%	211	-	-	-	1,314	1,525
38	464-00 Other Structures & Improvements	5,960	2.88%	172	-	-	-	1,365	1,537
39	465-00 Mains	772,849 *	1.63%	12,597	-	(1,063)	-	182,855	194,389
40	465-00 Mains - INSPECTION	1,748	Term	691	-	-	-	-	691
41	465-10 Mains - Byron Creek	932	5.00%	47	-	-	-	794	841
42	466-00 Compressor Equipment	111,930	3.18%	3,559	-	-	-	35,074	38,633
43	466-00 Compressor Equipment - OVERHAUL	-	Term	-	-	-	-	-	-
44	467-00 Measuring & Regulating Equipment	29,409	7.19%	2,115	-	-	-	6,266	8,381
45	467-10 Telemetering	8,547	1.33%	114	-	-	-	6,083	6,197
46	467-20 Measuring & Regulating Equipment - Byron Cr	39	4.01%	2	-	-	-	7	9
47	468-00 Communication Structures & Equipment	346	5.32%	18	-	-	-	277	295
48	469-00 Other Transmission Equipment	-	0.00%	-	-	-	-	-	-
49	TOTAL TRANSMISSION PLANT	958,807		20,090	-	(1,063)	-	239,700	258,727
50									
51	* Adjusted for full year impact of 2009 Fraser River SBSA CPCN.								

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2010 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Accumulated 12/31/2009	Accumulated 12/31/2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**DISTRIBUTION PLANT**								
2	470-00 Land in Fee Simple	$3,418	0.00%	$0	$0	$0	$0	$30	$30
3	472-00 Structures & Improvements	14,697	3.60%	529	-	-	-	3,231	3,760
4	472-10 Structures & Improvements - Byron Creek	107	5.00%	5	-	-	-	16	21
5	473-00 Services	652,084 **	2.25%	14,672	-	(7,790)	-	78,219	85,101
6	473-00 Services - LILO	43,229	2.20%	951	-	-	-	16,079	17,030
7	474-00 House Regulators & Meter Installations	135,704	5.21%	7,070	-	(11,032)	-	(2,418)	(6,380)
8	474-00 House Regulators & Meter Installations - LILO	16,070	2.19%	352	-	-	-	8,272	8,624
9	475-00 Mains	853,924	1.89%	16,139	-	(2,192)	-	235,807	249,754
10	475-00 Mains - LILO	39,704	2.00%	794	-	-	-	15,605	16,399
11	476-00 Compressor Equipment	571	25.04%	143	-	-	-	403	546
12	477-00 Measuring & Regulating Equipment	84,860	5.72%	4,854	-	(817)	-	12,756	16,793
13	477-00 Telemetering	6,038	0.25%	15	-	(13)	-	6,386	6,388
14	477-10 Measuring & Regulating Equipment - Byron Cree	163	0.00%	-	-	-	-	200	200
15	478-10 Meters	185,755	5.31%	9,864	-	(7,907)	-	38,504	40,461
16	478-11 Meters - LILO	10,027	3.29%	330	-	-	-	4,067	4,397
17	478-20 Instruments	11,251	4.03%	453	-	-	-	2,815	3,268
18	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-	-
19		2,057,601		56,171	-	(29,751)	-	419,972	446,392
20									
21	**GENERAL PLANT & EQUIPMENT**								
22	480-00 Land in Fee Simple	21,968	0.00%	-	-	-	-	13	13
23	481-00 Land Rights	-	0.00%	-	-	-	-	-	-
24	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-	-
25	- Frame Buildings	5,286	3.67%	194	4,633	-	-	(3,059)	1,768
26	- Masonry Buildings	84,641	2.50%	2,116	1,048	-	-	7,996	11,160
27	- Leasehold Improvement	557	10.00%	56	218	-	-	88	362
28	Office Equipment & Furniture	-	0.00%	-	-	-	-	-	-
29	483-30 GP Office Equipment	4,479	6.67%	299	726	(90)	-	1,937	2,872
30	483-40 GP Furniture	19,983	5.00%	999	(824)	(5)	-	12,176	12,346
31	483-10 GP Computer Hardware	17,347	20.00%	3,469	(7,882)	(6,245)	-	17,871	7,213
32	483-20 GP Computer Software	843	20.00%	169	-	(20)	-	445	594
33	483-21 GP Computer Software	-	0.00%	-	-	-	-	-	-
34	484-00 Transportation Equipment	3,094	7.70%	238	(2,099)	-	-	2,832	971
35	484-00 Vehicles - Leased	26,877	Lease Term	2,464	14,066	(2,321)	-	-	14,209
36	485-10 Heavy Work Equipment	209	6.64%	14	39	-	-	73	126
37	485-20 Heavy Mobile Equipment	576	8.48%	49	424	-	-	(332)	141
38	486-00 Small Tools & Equipment	32,746	5.00%	1,637	570	-	-	14,380	16,587
39	487-00 Equipment on Customer's Premises	24	6.67%	2	-	-	-	6	8
40	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-	-
41	488-00 Communications Equipment	-	0.00%	-	-	-	-	-	-
42	- Telephone	11,390	6.67%	760	506	(202)	-	5,647	6,711
43	- Radio	4,998	6.67%	333	(696)	-	-	2,527	2,164
44	489-00 Other General Equipment	-	0.00%	-	-	-	-	-	-
45	TOTAL GENERAL PLANT	235,016		12,799	10,729	(8,883)	-	62,600	77,245
46									
47	**UNCLASSIFIED PLANT**								
48	499 Plant Suspense	-	0.00%	-	-	-	-	(7)	(7)
49	TOTAL UNCLASSIFIED PLANT	-		-	-	-	-	(7)	(7)
50									
51	TOTALS	$3,411,233		$99,224	$6,465	($50,498)	$0	$780,174	$835,365
52		(X-Ref - Tab C-13, Schedule 45)						(X-Ref - Tab C-13, Schedule 8)	
53	Less: Capital Lease Vehicle Depreciation allocated to Capital Projects			(912)					
54									
55	**Net Depreciation Expense**			$98,312					
56				(X-Ref - Tab C-13, Schedule 33)					
57	** Adjusted for full year impact of 2009 Vancouver LP Replacement CPCN.								

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust-ments	Provision Retirements	Retirement Costs	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**								
2	117-00 Utility Plant Acquisition Adjustment	$0	1.00%	$0	$0	$0	$0	$0	$0
3	175-00 Unamortized Conversion Expense	109	1.00%	1	-	-	-	366	367
4	175-00 Unamortized Conversion Expense - Squamish	777	10.00%	78	-	-	-	234	312
5	178-00 Organization Expense	728	1.00%	7	-	-	-	376	383
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	19.76%	20	-	-	-	69	89
8	402-00 Utility Plant Acquisition Adjustment	63	23.66%	15	-	-	-	42	57
9	402-00 Other Intangible Plant	688	2.14%	15	-	-	-	166	181
10	461-00 Land Rights - Transmission	43,965	0.00%	-	-	-	-	651	651
11	461-10 Land Rights - Transmission - Byron Creek	16	0.00%	-	-	-	$0	$19	19
12	471-00 Land Rights - Distribution	1,065	0.00%	-	-	-	-	2	2
13	471-10 Land Rights - Distribution - Byron Creek	-	0.00%	-	-	-	-	1	1
14	402-01 Application Software - 12.5%	58,457	12.50%	7,307	-	(10,840)	-	25,102	21,569
15	402-02 Application Software - 20%	5,631	20.00%	1,126	-	(1,147)	-	3,739	3,718
16	TOTAL INTANGIBLE PLANT	111,598		8,569	-	(11,987)	-	30,767	27,349
17									
18	**MANUFACTURED GAS / LOCAL STORAGE**								
19	430 Manufact'd Gas - Land	31	0.00%	-	-	-	-	-	-
20	432 Manufact'd Gas - Struct. & Improvements	475	3.28%	16	-	-	-	105	121
21	433 Manufact'd Gas - Equipment	850	6.30%	54	-	-	-	91	145
22	434 Manufact'd Gas - Gas Holders	663	3.90%	26	-	-	-	199	225
23	436 Manufact'd Gas - Compressor Equipment	53	4.96%	3	-	-	-	27	30
24	437 Manufact'd Gas - Measuring & Regulating Equipm	309	19.50%	60	-	-	-	212	272
25	440/441 Land in Fee Simple and Land Rights	928	0.00%	-	-	-	-	1	1
26	442 Structures & Improvements	4,885	3.65%	178	-	-	-	2,430	2,608
27	443 Gas Holders - Storage	18,134	2.18%	395	-	-	-	10,053	10,448
28	446 Compressor Equipment	-	0.00%	-	-	-	-	-	-
29	447 Measuring & Regulating Equipment	-	0.00%	-	-	-	-	-	-
30	448 Purification Equipment	-	0.00%	-	-	-	-	-	-
31	449 Local Storage Equipment	23,410	3.36%	787	-	-	-	9,123	9,910
32	TOTAL MANUFACTURED GAS / LOCAL STORA(	49,738		1,519	-	-	-	22,241	23,760
33									
34	**TRANSMISSION PLANT**								
35	460-00 Land in Fee Simple	7,408	0.00%	-	-	-	-	401	401
36	462-00 Compressor Structures	14,690	3.84%	564	-	-	-	5,828	6,392
37	463-00 Measuring Structures	4,949	4.27%	211	-	-	-	1,525	1,736
38	464-00 Other Structures & Improvements	5,960	2.88%	172	-	-	-	1,537	1,709
39	465-00 Mains	790,899	1.63%	12,892	-	(942)	-	194,389	206,339
40	465-00 Mains - INSPECTION	3,719	Term	553	-	-	-	691	1,244
41	465-10 Mains - Byron Creek	932	5.00%	47	-	-	-	841	888
42	466-00 Compressor Equipment	113,748	3.18%	3,617	-	-	-	38,633	42,250
43	466-00 Compressor Equipment - OVERHAUL	-	Term	-	-	-	-	-	-
44	467-00 Measuring & Regulating Equipment	29,409	7.19%	2,115	-	-	-	8,381	10,496
45	467-10 Telemetering	8,636	1.33%	115	-	-	-	6,197	6,312
46	467-20 Measuring & Regulating Equipment - Byron Cr	39	4.01%	2	-	-	-	9	11
47	468-00 Communication Structures & Equipment	346	5.32%	18	-	-	-	295	313
48	469-00 Other Transmission Equipment	-	0.00%	-	-	-	-	-	-
49	TOTAL TRANSMISSION PLANT	980,734		20,306	-	(942)	-	258,727	278,091

TERASEN GAS INC. — Nov 5, 2009 NSP Agreement — Section C, Tab 13, Schedule 51

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account (1)	Mid-year GPIS for Depreciation (2)	Annual Depreciation Rate % (3)	Provision: 2011 (Cr.) (4)	Provision: Adjust-ments (5)	Provision: Retirements (6)	Provision: Retirement Costs (7)	Accumulated 12/31/2010 (8)	Accumulated 12/31/2011 (9)
1	**DISTRIBUTION PLANT**								
2	470-00 Land in Fee Simple	$3,418	0.00%	$0	$0	$0	$0	$30	$30
3	472-00 Structures & Improvements	14,697	3.60%	529	-	-	-	3,760	4,289
4	472-10 Structures & Improvements - Byron Creek	107	5.00%	5	-	-	-	21	26
5	473-00 Services	676,435	2.25%	15,220	-	(8,444)	-	85,101	91,877
6	473-00 Services - LILO	43,229	2.20%	951	-	-	-	17,030	17,981
7	474-00 House Regulators & Meter Installations	138,565	5.21%	7,219	-	(11,859)	-	(6,380)	(11,020)
8	474-00 House Regulators & Meter Installations - LILO	16,070	2.19%	352	-	-	-	8,624	8,976
9	475-00 Mains	873,883	1.89%	16,516	-	(2,244)	-	249,754	264,026
10	475-00 Mains - LILO	39,704	2.00%	794	-	-	-	16,399	17,193
11	476-00 Compressor Equipment	571	25.04%	143	-	-	-	546	689
12	477-00 Measuring & Regulating Equipment	89,546	5.72%	5,122	-	(838)	-	16,793	21,077
13	477-00 Telemetering	6,283	0.25%	16	-	(13)	-	6,388	6,391
14	477-10 Measuring & Regulating Equipment - Byron Cre€	163	0.00%	-	-	-	-	200	200
15	478-10 Meters	187,782	5.31%	9,971	-	(8,313)	-	40,461	42,119
16	478-11 Meters - LILO	10,027	3.29%	330	-	-	-	4,397	4,727
17	478-20 Instruments	11,251	4.03%	453	-	-	-	3,268	3,721
18	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-	-
19		2,111,730		57,621	-	(31,711)	-	446,392	472,302
20									
21	**GENERAL PLANT & EQUIPMENT**								
22	480-00 Land in Fee Simple	22,096	0.00%	-	-	-	-	13	13
23	481-00 Land Rights	-	0.00%	-	-	-	-	-	-
24	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-	-
25	- Frame Buildings	5,286	3.67%	194	-	-	-	1,768	1,962
26	- Masonry Buildings	87,190	2.50%	2,180	-	-	-	11,160	13,340
27	- Leasehold Improvement	667	10.00%	67	-	-	-	362	429
28	Office Equipment & Furniture	-	0.00%	-	-	-	-	-	-
29	483-30 GP Office Equipment	4,012	6.67%	268	-	(991)	-	2,872	2,149
30	483-40 GP Furniture	19,830	5.00%	991	-	(1,230)	-	12,346	12,107
31	483-10 GP Computer Hardware	18,979	20.00%	3,796	-	-	-	7,213	11,009
32	483-20 GP Computer Software	734	20.00%	147	-	(198)	-	594	543
33	483-21 GP Computer Software	-	0.00%	-	-	-	-	-	-
34	484-00 Transportation Equipment	4,712	7.70%	363	-	-	-	971	1,334
35	484-00 Vehicles - Leased	28,198	Lease Term	2,709	-	(1,641)	-	14,209	15,277
36	485-10 Heavy Work Equipment	209	6.64%	14	-	-	-	126	140
37	485-20 Heavy Mobile Equipment	606	8.48%	51	-	-	-	141	192
38	486-00 Small Tools & Equipment	33,867	5.00%	1,693	-	-	-	16,587	18,280
39	487-00 Equipment on Customer's Premises	24	6.67%	2	-	-	-	8	10
40	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-	-
41	488-00 Communications Equipment	-	0.00%	-	-	-	-	-	-
42	- Telephone	10,975	6.67%	732	-	(1,596)	-	6,711	5,847
43	- Radio	4,706	6.67%	314	-	(954)	-	2,164	1,524
44	489-00 Other General Equipment	-	0.00%	-	-	-	-	-	-
45	TOTAL GENERAL PLANT	242,088		13,521	-	(6,610)	-	77,245	84,156
46									
47	**UNCLASSIFIED PLANT**								
48	499 Plant Suspense	-	0.00%	-	-	-	-	(7)	(7)
49	TOTAL UNCLASSIFIED PLANT	-		-	-	-	-	(7)	(7)
50									
51	TOTALS	$3,495,886		$101,536	$0	($51,250)	$0	$835,365	$885,651
52		(X-Ref - Tab C-13, Schedule 47)						(X-Ref - Tab C-13, Schedule 9)	
53	Less: Capital Lease Vehicle Depreciation allocated to Capital Projects			(1,002)					
54									
55	**Net Depreciation Expense**			$100,534					
56				(X-Ref - Tab C-13, Schedule 34)					

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 52

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Balance 12/31/2009	Adjustment	2010 Additions	2010 Retirements	Balance 12/31/2010	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$141,389	$0	$6,424	$0	$147,813	
4							
5	Transmission Contributions	10,915	-	4,550	-	15,465	
6							
7	Others	-	-	-	-	-	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	24,541	-	-	(3,934)	20,607	
11							
12	TOTAL Contributions	176,845	-	10,974	(3,934)	183,885	(X-Ref - Tab C-13, Schedule 8)
13							(X-Ref - Tab C-13, Schedule 41)
14							
15							
16	**Amortization**						
17							
18	Distribution Contributions	(32,291)	-	(3,765)	-	(36,056)	
19							
20	Transmission Contributions	-	-	(263)	-	(263)	
21							
22	Others	(1)	-	-	-	(1)	
23							
24	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
25	- Infrastructure/Custom	(11,854)	-	(2,822)	3,934	(10,742)	
26							
27	TOTAL Amortization	(44,146)	-	(6,850)	3,934	(47,062)	(X-Ref - Tab C-13, Schedule 8)
28							(X-Ref - Tab C-13, Schedule 41)
29	**NET CONTRIBUTIONS**	$132,699	$0	$4,124	$0	$136,823	

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
CONTRIBUTIONS IN AID OF CONSTRUCTION Schedule 53
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	Adjustment	2011 Additions	2011 Retirements	Balance 12/31/2011	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$147,813	$0	$6,029	$0	$153,842	
4							
5	Transmission Contributions	15,465	-	8,333	-	23,798	
6							
7	Others	-	-	-	-	-	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	20,607	-	-	(3,494)	17,113	
11							
12	TOTAL Contributions	183,885	-	14,362	(3,494)	194,753	(X-Ref - Tab C-13, Schedule 9)
13							(X-Ref - Tab C-13, Schedule 42)
14							
15							
16	**Amortization**						
17							
18	Distribution Contributions	(36,056)	-	(3,928)	-	(39,984)	
19							
20	Transmission Contributions	(263)	-	(391)	-	(654)	
21							
22	Others	(1)	-	-	-	(1)	
23							
24	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
25	- Infrastructure/Custom	(10,742)	-	(2,358)	3,494	(9,606)	
26							
27	TOTAL Amortization	(47,062)	-	(6,677)	3,494	(50,245)	(X-Ref - Tab C-13, Schedule 9)
28							(X-Ref - Tab C-13, Schedule 42)
29	**NET CONTRIBUTIONS**	$136,823	$0	$7,685	$0	$144,508	

TERASEN GAS INC.

Nov 5, 2009 NSP Agreement

Section C
Tab 13
Schedule 54

APPENDIX A
to Order G-141-09
Page 75 of 110

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Forecast Balance 12/31/2009	Opening Balance Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2010	Mid-Year Average 2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Commodity Cost Reconciliation Account (CCRA)	($22,742.7)	$0.0	$31,808.0	($9,065.3)	$22,742.7	$0.0	$0.0	$0.0	$0.0	($11,371.4)
3	CCRA Interest	(895.9)		1,253.0	(357.1)	895.9	-	-	-	(0.0)	(448.0)
4	Midstream Cost Reconciliation Account (MCRA)	36,423.3		(50,941.7)	14,518.4	(36,423.3)	-	-	-	(0.0)	18,211.7
5	MCRA Interest	(1,779.2)		2,488.4	(709.2)	1,779.2	-	-	-	-	(889.6)
6	Revenue Stabilization Adjustment Mechanism (RSAM)	(13,165.6)		-	-	-	-	6,137.8	(1,749.3)	(8,777.1)	(10,971.4)
7	RSAM Interest	(38.4)		(5.3)	1.5	(3.8)	-	18.3	(5.2)	(29.1)	(33.8)
8	Revelstoke Propane Cost Deferral Account	(38.8)		54.3	(15.5)	38.8	-	-	-	(0.0)	(19.4)
9	SCP Mitigation Revenues Variance Account	(4,118.1)	(1,538.2)	-	-	-	1,723.2	-	-	(3,933.1)	(4,794.7)
10	SCP West to East Transmission	(1,538.2)	1,538.2	-	-	-	-	-	-	-	-
11											
12	Energy Policy Related										
13	Energy Efficiency & Conservation (EEC)	6,370.2		25,845.0	(7,365.8)	18,479.2	(1,012.0)	-	-	23,837.4	15,103.8
14	NGV Conversion Grants	136.9		77.5	(22.1)	55.4	(43.5)	-	-	148.8	142.9
15											
16	Non-Controllable Items										
17	Property Tax Deferral	(743.8)		-	-	-	398.1	-	-	(345.7)	(544.8)
18	Insurance Variance	(686.0)		-	-	-	686.0	-	-	-	(343.0)
19	Pension & OPEB Variance	(686.4)		-	-	-	686.4	-	-	-	(343.2)
20	BCUC Levies Variance	(262.0)		-	-	-	262.0	-	-	-	(131.0)
21	Interest Variance	(2,232.2)		-	-	-	633.9	-	-	(1,598.3)	(1,915.3)
22	Interest Variance - Funding benefits via Customer Deposits	214.2		-	-	-	(13.1)	-	-	201.1	207.7
23	Income Tax Rate Variance	(615.9)		-	-	-	205.3	-	-	(410.6)	(513.3)
24	Olympics Security Costs Deferral	522.8		2,651.6	(755.7)	1,895.9	-	-	-	2,418.7	1,470.8
25	IFRS Conversion Costs	399.5		265.3	(75.6)	189.7	-	-	-	589.2	494.4
26											
27	Cost of Current Applications										
28	2009 ROE & Cost of Capital Application	$441.0		$0.0	$0.0	$0.0	($88.2)	$0.0	$0.0	$352.8	$396.9
29	2010-2011 Revenue Requirement Application	795.2		-	-	-	(397.6)	-	-	397.6	596.4
30	CCE CPCN Application	189.0		-	-	-	(37.8)	-	-	151.2	170.1
31											
32	Other										
33	IFRS Transitional Adjustments	-		(7,602.7)	-	(7,602.7)	-	-	-	(7,602.7)	(7,602.7)
34	OPEB Funding	(32,551.8)	32,551.8	-	-	-	-	-	-	-	(16,275.9)
35	Pension & OPEB Funding	-	(32,551.8)	20,476.7	-	20,476.7	-	-	-	(12,075.1)	(6,037.6)
36	2010 Revenue Surplus Deferral Account	-		(6,537.0)	-	(6,537.0)	-	-	-	(6,537.0)	(3,268.5)
37											
38	Residual Deferred Charges										
39	SCP Tax Reassessment	7,408.3		-	-	-	-	-	-	7,408.3	7,408.3
40	Deferred Service Line Installation Fee	1,442.9		(1,442.9)	-	(1,442.9)	-	-	-	-	-
41	Earnings Sharing Mechanism	(13,123.6)		3,372.0	(961.0)	2,411.0	-	6,168.7	(1,758.1)	(6,302.0)	(9,712.8)
42	CCT Assessment	(2.5)		-	-	-	2.5	-	-	-	(1.3)
43	Carbon Tax Implementation	(95.0)		-	-	-	95.0	-	-	-	(47.5)
44	TGS Amalgamation	132.0		-	-	-	(132.0)	-	-	-	66.0
45	TGS O&M Variance	352.0		-	-	-	(352.0)	-	-	-	176.0
46	Carbon Tax Cost of Service	(44.0)		-	-	-	44.0	-	-	(0.0)	(22.0)
47	OSC Certification Compliance	91.1		-	-	-	(91.1)	-	-	-	45.6
48	Bad Debt Allowance for Rates 14 & 14A	(140.2)	140.2	-	-	-	-	-	-	-	-
49											
50	Total Deferred Charges for Rate Base	($40,581.9)	$140.2	$21,762.2	($4,807.4)	$16,954.8	$2,569.1	$12,324.8	($3,512.6)	($12,105.6)	($30,796.6)
51							(X-Ref - Tab C-13, Schedule 33)			(X-Ref - Tab C-13, Schedule 8)	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Forecast Balance 12/31/2010	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2011	Mid-Year Average 2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Margin Related									
2	Commodity Cost Reconciliation Account (CCRA)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
3	CCRA Interest	(0.0)	-	-	-	-	-	-	(0.0)	-
4	Midstream Cost Reconciliation Account (MCRA)	(0.0)	-	-	-	-	-	-	(0.0)	-
5	MCRA Interest	-	-	-	-	-	-	-	-	-
6	Revenue Stabilization Adjustment Mechanism (RSAM)	(8,777.1)	-	-	-	-	5,970.8	(1,582.3)	(4,388.6)	(6,582.9)
7	RSAM Interest	(29.1)	199.0	(52.7)	146.3	-	19.3	(5.1)	131.4	51.2
8	Revelstoke Propane Cost Deferral Account	(0.0)	-	-	-	-	-	-	(0.0)	-
9	SCP Mitigation Revenues Variance Account	(3,933.1)	-	-	-	1,735.9	-	-	(2,197.2)	(3,065.2)
10	SCP West to East Transmission	-	-	-	-	-	-	-	-	-
11										
12	Energy Policy Related									
13	Energy Efficiency & Conservation (EEC)	23,837.4	29,619.0	(7,849.0)	21,770.0	(2,524.9)	-	-	43,082.5	33,460.0
14	NGV Conversion Grants	148.8	255.0	(67.6)	187.4	(51.1)	-	-	285.1	217.0
15										
16	Non-Controllable Items									
17	Property Tax Deferral	(345.7)	-	-	-	184.2	-	-	(161.5)	(253.6)
18	Insurance Variance	-	-	-	-	-	-	-	-	-
19	Pension & OPEB Variance	-	-	-	-	-	-	-	-	-
20	BCUC Levies Variance	-	-	-	-	-	-	-	-	-
21	Interest Variance	(1,598.3)	-	-	-	721.6	-	-	(876.7)	(1,237.5)
22	Interest Variance - Funding benefits via Customer Deposits	201.1	-	-	-	(13.1)	-	-	188.0	194.6
23	Income Tax Rate Variance	(410.6)	-	-	-	205.3	-	-	(205.3)	(308.0)
24	Olympics Security Costs Deferral	2,418.7	-	-	-	(806.2)	-	-	1,612.5	2,015.6
25	IFRS Conversion Costs	589.2	119.3	(31.6)	87.7	(196.4)	-	-	480.5	534.9
26										
27	Cost of Current Applications									
28	2009 ROE & Cost of Capital Application	$352.8	$0.0	$0.0	$0.0	($88.2)	$0.0	$0.0	$264.6	$308.7
29	2010-2011 Revenue Requirement Application	397.6	-	-	-	(397.6)	-	-	-	198.8
30	CCE CPCN Application	151.2	-	-	-	(37.8)	-	-	113.4	132.3
31										
32	Other									
33	IFRS Transitional Adjustments	(7,602.7)	68,819.0	-	68,819.0	-	-	-	61,216.3	26,806.8
34	OPEB Funding	-	-	-	-	-	-	-	-	-
35	Pension & OPEB Funding	(12,075.1)	(69,232.0)	-	(69,232.0)	-	-	-	(81,307.1)	(46,691.1)
36	2010 Revenue Surplus Deferral Account	(6,537.0)	-	-	-	6,537.0	-	-	-	(3,268.5)
37										
38	Residual Deferred Charges									
39	SCP Tax Reassessment	7,408.3	-	-	-	-	-	-	7,408.3	7,408.3
40	Deferred Service Line Installation Fee	-	-	-	-	-	-	-	-	-
41	Earnings Sharing Mechanism	(6,302.0)	1,686.0	(446.8)	1,239.2	-	6,888.2	(1,825.4)	-	(3,151.0)
42	CCT Assessment	-	-	-	-	-	-	-	-	-
43	Carbon Tax Implementation	-	-	-	-	-	-	-	-	-
44	TGS Amalgamation	-	-	-	-	-	-	-	-	-
45	TGS O&M Variance	-	-	-	-	-	-	-	-	-
46	Carbon Tax Cost of Service	(0.0)	-	-	-	-	-	-	(0.0)	-
47	OSC Certification Compliance	-	-	-	-	-	-	-	-	-
48	Bad Debt Allowance for Rates 14 & 14A	-	-	-	-	-	-	-	-	-
49										
50	Total Deferred Charges for Rate Base	($12,105.6)	$31,465.3	($8,447.7)	$23,017.6	$5,268.7	$12,878.3	($3,412.8)	$25,646.2	$6,770.4
51						(X-Ref - Tab C-13, Schedule 34)			(X-Ref - Tab C-13, Schedule 9)	

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 56

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing 2009 Rates	2010 Revised Revenue	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$2,324	$1,539	$1,539	($785)	- Tab C-13, Schedule 58
4						
5	Customer Deposits	-	0	-	-	
6						
7	Less - Funds Available:					
8						
9	Reserve for Bad Debts	(5,940)	(5,940)	(5,940)	-	
10						
11	Withholdings From Employees	(3,162)	(3,162)	(3,162)	-	
12						
13	Subtotal	(6,778)	(7,563)	(7,563)	(785)	(X-Ref - Tab C-13, Schedule 8)
14						(X-Ref - Tab C-13, Schedule 41)
15	**Other Working Capital Items**					
16	Construction Advances	(670)	(670)	(670)	-	
17	Transmission Line Pack Gas	2,413	2,413	2,413	-	
18	Gas in Storage	100,494	100,494	100,494	-	
19	Inventory - Materials & Supplies	1,202	1,202	1,202	-	
20						
21	Subtotal	103,439	103,439	103,439	0	(X-Ref - Tab C-13, Schedule 8)
22						(X-Ref - Tab C-13, Schedule 41)
23	Total	$96,661	$95,876	$95,876	($785)	

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C Tab 13 Schedule 57

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing 2009 Rates	2011 Revised Revenue	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$3,186	$2,366	$2,372	($814)	- Tab C-13, Schedule 58
4						
5	Customer Deposits	-	0	-	0	
6						
7	Less - Funds Available:					
8						
9	Reserve for Bad Debts	(6,063)	(6,063)	(6,063)	0	
10						
11	Withholdings From Employees	(3,256)	(3,256)	(3,256)	0	
12						
13	Subtotal	(6,133)	(6,953)	(6,947)	(814)	(X-Ref - Tab C-13, Schedule 9)
14						(X-Ref - Tab C-13, Schedule 42)
15	**Other Working Capital Items**					
16	Construction Advances	(670)	(670)	(670)	0	
17	Transmission Line Pack Gas	4,731	4,731	4,731	-	
18	Gas in Storage	114,804	114,804	114,804	0	
19	Inventory - Materials & Supplies	1,226	1,226	1,226	0	
20						
21	Subtotal	120,091	120,091	120,091	0	(X-Ref - Tab C-13, Schedule 9)
22						(X-Ref - Tab C-13, Schedule 42)
23	Total	$113,958	$113,138	$113,144	($814)	

CASH WORKING CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009 Days	2009 Expenses	2009 Cash Working Capital	2010 Days	2010 Expenses	2010 Cash Working Capital	2011 Days	2011 Expenses	2011 Cash Working Capital	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**CASH WORKING CAPITAL**										
2											
3	Revenue Lag Days	35.0			38.8			38.8			- Tab C-13, Schedule 59
4	Expense Lead Days	39.0			38.4			38.2			- Tab C-13, Schedule 60
5											(X-Ref - Tab C-13, Schedule 56)
6	Net Lead/(Lag) Days	(4.0)	$1,306,297	($14,316)	0.4	$1,404,291	$1,539	0.6	$1,439,545	$2,366	(X-Ref - Tab C-13, Schedule 57)
7											
8											
9											
10	**CASHWORKING CAPITAL, REVISED RATES**										
11											
12	Revenue Lag Days	35.0			38.8			38.8			- Tab C-13, Schedule 59
13	Expense Lead Days	39.0			38.4			38.2			- Tab C-13, Schedule 60
14											(X-Ref - Tab C-13, Schedule 56)
15	Net Lead/(Lag) Days	(4.0)	$1,306,297	($14,316)	0.4	$1,404,291	$1,539	0.6	$1,443,164	$2,372	(X-Ref - Tab C-13, Schedule 57)
16											
17											
18											
19	**CASH WORKING CAPITAL CHANGE**			$0			$0			$6	
20											
21											
22											
23	Cash working capital = Col. 2 x Col. 3 / 365 days										

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 59

CASH WORKING CAPITAL
LAG TIME FROM DATE OF PAYMENT TO RECEIPT OF CASH
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

		2009			2010			2011			
Line No.	Particulars	Revenue At 2009 Rates	Lag Days Service to Collection	Dollar Days	Revenue At 2009 Rates	Lag Days Service to Collection	Dollar Days	Revenue At 2009 Rates	Lag Days Service to Collection	Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**REVENUE**										
2											- Tab C-13, Schedule 22
3	Gas Sales and Transportation Service Revenue										- Tab C-13, Schedule 24
4	Residential and Commercial	$1,344,218	34.6	$46,509,939	$1,399,982	38.3	$53,675,914	$1,402,286	38.3	$53,763,147	
5	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	78,860	41.0	3,233,260	77,496	45.0	3,489,083	77,608	45.0	3,494,126	
6	NGV Fuel - Stations	1,076	38.7	41,657	1,044	41.7	43,552	1,044	41.7	43,552	
7											
8	Rates 22, Burrard, TGVI (Oth Rev), SCP (Oth Rev)	40,576	37.8	1,533,765	42,054	42.5	1,788,524	44,031	42.3	1,864,247	
9											
10	Total Gas Sales	1,464,730	35.0	51,318,621	1,520,576	38.8	58,997,073	1,524,969	38.8	59,165,072	
11					(X-Ref - Tab C-13, Schedule 2)			(X-Ref - Tab C-13, Schedule 3)			- Tab C-13, Schedule 26
12	Other Revenues										- Tab C-13, Schedule 27
13	Late Payment Charges	2,878	26.7	76,843	3,014	38.3	115,444	3,020	38.3	115,681	
14	Returned Cheque Charges	84	31.8	2,671	82	38.3	3,140	82	38.3	3,140	
15	Connection Charges	2,926	37.3	109,140	2,880	38.3	110,315	2,907	38.3	111,323	
16	Other Utility Income	277	34.9	9,667	203	38.4	7,791	132	38.2	5,040	
17											
18											
19	Total Revenue	$1,470,895	35.0	$51,516,942	$1,526,755	38.8	$59,233,763	$1,531,110	38.8	$59,400,256	
20											
21											
22	**REVENUE, REVISED RATES**										
23											- Tab C-13, Schedule 22
24	Gas Sales and Transportation Service Revenue										- Tab C-13, Schedule 24
25	Residential and Commercial	$1,344,218	34.6	$46,509,939	$1,399,982	38.3	$53,675,914	$1,412,450	38.3	$54,152,948	
26	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	78,860	41.0	3,233,260	77,496	45.0	3,489,083	78,866	45.0	3,550,934	
27	NGV Fuel - Stations	1,076	38.7	41,657	1,044	41.7	43,552	1,053	41.7	43,927	
28											
29	Rates 22, Burrard, TGVI, SCP (Other)	40,576	37.8	1,533,765	42,054	42.5	1,788,524	44,354	42.4	1,878,846	
30											
31	Total Gas Sales	1,464,730	35.0	51,318,621	1,520,576	38.8	58,997,073	1,536,723	38.8	59,626,655	
32											- Tab C-13, Schedule 26
33	Other Revenues										- Tab C-13, Schedule 27
34	Late Payment Charges	2,878	26.7	76,843	3,014	38.3	115,444	3,020	38.3	115,681	
35	Returned Cheque Charges	84	31.8	2,671	82	38.3	3,140	82	38.3	3,140	
36	Connection Charges	2,926	37.3	109,140	2,880	38.3	110,315	2,907	38.3	111,323	
37	Other Utility Income	277	34.9	9,667	203	38.4	7,791	132	38.2	5,040	
38											
39											
40	Total Revenue	$1,470,895	35.0	$51,516,942	$1,526,755	38.8	$59,233,763	$1,542,864	38.8	$59,861,839	

CASH WORKING CAPITAL
LEAD TIME IN PAYMENT OF EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

		2009			2010			2011			
Line No.	Particulars	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**EXPENSES**										
2											
3	Operating And Maintenance										- Tab C-13, Schedule 4
4	Expenses	$166,966	19.3	$3,222,444	$177,559	25.5	$4,527,755	$184,625	25.5	$4,707,938	- Tab C-13, Schedule 5
5											- Tab C-13, Schedule 4
6	Gas Purchases	930,677	40.7	37,878,554	987,970	40.2	39,716,394	989,627	40.2	39,783,006	- Tab C-13, Schedule 5
7											
8	Taxes Other Than Income										- Tab C-13, Schedule 31
9	Property Taxes	47,593	4.0	190,372	49,193	2.0	98,386	50,211	2.0	100,422	- Tab C-13, Schedule 32
10	Franchise Fees	10,044	430.0	4,318,920	10,259	420.3	4,311,858	10,292	420.3	4,325,728	
11	Carbon Tax	71,753	43.6	3,128,449	98,953	29.1	2,879,519	127,206	29.1	3,701,686	
12	GST - Net	12,520	7.2	90,131	12,997	38.8	504,291	13,034	38.8	505,738	
13	PST	40,647	43.6	1,772,209	42,437	37.1	1,574,413	43,101	37.1	1,599,047	
14	Income Tax	26,096	15.2	396,659	24,923	15.2	378,830	21,449	15.2	326,025	- Tab C-13, Schedule 6
15											- Tab C-13, Schedule 7
16	Total	$1,306,296	39.0	$50,997,738	$1,404,291	38.4	$53,991,446	$1,439,545	38.2	$55,049,590	
17											
18											
19	**EXPENSES, REVISED RATES**										
20											
21	Operating And Maintenance										- Tab C-13, Schedule 4
22	Expenses	$166,966	19.3	$3,222,444	$177,559	25.5	$4,527,755	$184,625	25.5	$4,707,938	- Tab C-13, Schedule 5
23											- Tab C-13, Schedule 4
24	Gas Purchases	930,677	40.7	37,878,554	987,970	40.2	39,716,394	989,627	40.2	39,783,006	- Tab C-13, Schedule 5
25											
26	Taxes Other Than Income										- Tab C-13, Schedule 31
27	Property Taxes	47,593	4.0	190,372	49,193	2.0	98,386	50,211	2.0	100,422	- Tab C-13, Schedule 32
28	Franchise Fees	10,044	430.0	4,318,920	10,259	420.3	4,311,858	10,376	420.3	4,361,033	
29	Carbon Tax	71,753	43.6	3,128,449	98,953	29.1	2,879,519	127,206	29.1	3,701,686	
30	GST - Net	12,520	7.2	90,131	12,997	38.8	504,291	13,136	38.8	509,665	
31	PST	40,647	43.6	1,772,209	42,437	37.1	1,574,413	43,420	37.1	1,610,882	
32	Income Tax	26,096	15.2	396,659	24,923	15.2	378,830	24,564	15.2	373,373	- Tab C-13, Schedule 6
33											- Tab C-13, Schedule 7
34	Total	$1,306,296	39.0	$50,997,738	$1,404,291	38.4	$53,991,446	$1,443,164	38.2	$55,148,005	

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
Tab 13
Schedule 61

FUTURE INCOME TAX LIABILITY / ASSET
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009	2010	2011
	(1)	(2)	(3)	(4)
1	Property Plant & Equipment			
2	Net Book Value *	($2,447,020)	($2,535,462)	($2,625,708)
3	Less: Undepreciated Capital Cost	(1,712,991)	(1,760,477)	(1,853,515)
4		(734,029)	(774,985)	(772,193)
5	Weighted Average Future Tax Rate	25%	25%	25%
6		(184,037)	(194,075)	(193,048)
7				
8	Total FIT Liability- After Tax (PP&E)	(184,037)	(194,075)	(193,048)
9	Total FIT Liability- After Tax (Non-PP&E)	(24,298)	(23,948)	(27,038)
10	Total FIT Liability- After Tax	(208,335)	(218,023)	(220,086)
11				
12	Tax Gross Up	(69,713)	(72,839)	(73,362)
13				
14	FIT Liability/Asset - End of Year	(278,048)	(290,862)	(293,448)
15				
16	FIT Liability/Asset - Opening Balance	(278,048)	(278,048)	(290,862)
17				
18	FIT Liability/Asset - Mid Year	(278,048)	(284,455)	(292,155)
19		(X-Ref - Tab C-13, Schedule 8)	(X-Ref - Tab C-13, Schedule 9)	
20			(X-Ref - Tab C-13, Schedule 41)	
21	Note: * Excludes Land, Software CIAC, and WIP.		(X-Ref - Tab C-13, Schedule 42)	

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
RETURN ON CAPITAL | Tab 13
FOR THE YEAR ENDING DECEMBER 31, 2010 | Schedule 62
($000s)

Line No.	Particulars	Reference	-------- Capitalization --------	Amount	%	Average Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2010 AT 2009 RATES							
2	Long-Term Debt	- Tab C-13, Schedule 64		$1,558,326	61.490%	6.870%	4.220%	$107,064
3	Unfunded Debt			88,809	3.500%	2.250%	0.080%	1,998
4	Common Equity			887,309	35.010%	8.483%	2.970%	75,270
5								
6		- Tab C-13, Schedule 8		$2,534,444	100.000%		7.270%	$184,332
7								
8	2010 REVISED RATES - FORECAST							
9	Long-Term Debt			$1,558,326	61.490%	6.870%	4.220%	$107,064
10	Unfunded Debt		$88,809					
11	Adjustment, Revised Rates		0	88,809	3.500%	2.250%	0.080%	1,998
12	Common Equity			887,309	35.010%	8.470%	2.970%	75,155
13								
14		- Tab C-13, Schedule 8		$2,534,444	100.000%		7.269%	$184,217
15							(X-Ref - Tab C-13, Schedule 4)	

TERASEN GAS INC.
RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Nov 5, 2009 NSP Agreement

Section C
Tab 13
Schedule 63

Line No.	Particulars	Reference	Capitalization (3)	Capitalization Amount (4)	%	Average Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2011 At 2010 Rates							
2	Long-Term Debt	- Tab C-13, Schedule 65		$1,631,453	62.060%	6.836%	4.242%	$111,518
3	Unfunded Debt			76,982	2.930%	4.500%	0.132%	3,464
4	Common Equity			920,331	35.010%	7.529%	2.636%	69,292
5								
6		- Tab C-13, Schedule 9		$2,628,766	100.000%		7.010%	$184,274
7								
8	2011 REVISED RATES - FORECAST							
9	Long-Term Debt			$1,631,453	62.060%	6.836%	4.242%	$111,518
10	Unfunded Debt		$76,982					
11	Adjustment, Revised Rates		4	76,986	2.930%	4.500%	0.132%	3,464
12	Common Equity			920,333	35.010%	8.470%	2.965%	77,952
13								
14		- Tab C-13, Schedule 9		$2,628,772	100.000%		7.339%	$192,934
15							(X-Ref - Tab C-13, Schedule 5)	

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 64

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$58,943	$855 *	$65,598	12.054%	$66,453	$8,010	
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	155,046	10.461%	157,274	16,452	
3											
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710	7.073%	150,000	10,610	
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085	6.598%	150,000	9,897	
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337	5.980%	150,000	8,970	
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216	5.595%	120,000	6,714	
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697	6.067%	250,000	15,168	
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,389	247,611	5.868%	250,000	14,670	
10	2009 Medium Term Debt Issue- Series 24 (includes replacement for Series E)	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000	99,000	6.627%	100,000	6,627	
11	2009 Medium Term Debt Issue- Series 25	1-Apr-2010	1-Apr-2020	5.188%	100,000	1,000	99,000	5.318%	75,342	4,007	
12									-	-	
13											
14	LILO Obligations - Kelowna							5.905%	26,735	1,579	
15	LILO Obligations - Nelson							7.011%	4,258	299	
16	LILO Obligations - Vernon							8.150%	12,731	1,038	
17	LILO Obligations - Prince George							7.171%	32,685	2,344	
18	LILO Obligations - Creston							6.418%	3,098	199	
19											
20	Vehicle Lease Obligation							5.380%	12,740	685	
21											
22									$1,561,316	$107,269	
23											
24	Sub-Total								$1,561,316	$107,269	
25	Less - Fort Nelson Division Portion of Long Term Debt								(2,990)	(205)	
26	Total								$1,558,326	$107,064	
27								(X-Ref - Tab C-13, Schedule 10)		, (X-Ref - Tab C-13, Schedule 62)	
28	*Includes adjustment of $5,049 for BC Hydro Premium								Average Embedded Cost	6.870%	

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 65

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue		Effective Interest Cost	Average Principal Outstanding	Annual Cost	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)	(11)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$58,943	$855	$65,990	*	12.054%	$66,845	$8,057	
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	155,046		10.461%	157,274	16,452	
3												
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710		7.073%	150,000	10,610	
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085		6.598%	150,000	9,897	
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337		5.980%	150,000	8,970	
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216		5.595%	120,000	6,714	
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697		6.067%	250,000	15,168	
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,389	247,611		5.868%	250,000	14,670	
10	2009 Medium Term Debt Issue- Series 24 (includes replacement for Series E)	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000	99,000		6.627%	100,000	6,627	
11	2009 Medium Term Debt Issue- Series 25	1-Apr-2010	1-Apr-2020	5.188%	100,000	1,000	99,000		5.318%	100,000	5,318	
12	2011 Medium Term Debt Issue- Series 26	1-Jul-2011	1-Jul-2021	5.650%	100,000	1,000	99,000		5.783%	50,411	2,915	
13												
14	LILO Obligations - Kelowna								5.919%	25,729	1,523	
15	LILO Obligations - Nelson								7.093%	4,110	292	
16	LILO Obligations - Vernon								8.242%	12,267	1,011	
17	LILO Obligations - Prince George								7.256%	31,571	2,291	
18	LILO Obligations - Creston								6.496%	2,996	195	
19												
20	Vehicle Lease Obligation								7.631%	13,455	1,027	
21												
22										$1,634,658	$111,737	
23												
24	Sub-Total									$1,634,658	$111,737	
25	Less - Fort Nelson Division Portion of Long Term Debt									(3,205)	(219)	
26	Total									$1,631,453	$111,518	
27									(X-Ref - Tab C-13, Schedule 11)	(X-Ref - Tab C-13, Schedule 63)		
28	*Includes adjustment of $7,772 for BC Hydro Premium									Average Embedded Cost	6.836%	

TERASEN GAS INC.

Nov 5, 2009 NSP Agreement — Section C, Tab 13, Schedule 66

GROSS MARGIN RECONCILIATION WITH 2010 RATES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line		Proposed Base Delivery Rate			Approved Basic Charge & Admin Fee				Proposed Demand Charge			Collected	Required	Margin
No.	Particulars	Rate	Terajoules	($000)	Rate	Customers	Adj Factor	($000)	Rate	Terajoules	($000)	Margin	Margin	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	**NON-BYPASS**													
2	Core Sales													
3	Schedule 1 - Residential	2.961	69,174.3	$204,825	11.840	754,076	-1.20%	$105,858	-	-	$0	$310,683	$310,678	$5
4	Schedule 2 - Small Commercial	2.479	24,374.3	60,424	24.840	76,536	-4.54%	21,777	-	-	-	82,201.3	82,199.7	1.6
5	Schedule 3 - Large Commercial	2.136	16,818.6	35,925	132.520	5,022	-0.50%	7,945	-	-	-	43,869.8	43,869.5	0.3
6	Total Schedules 1 , 2 and 3		110,367.2	301,174		835,633		135,580		-	-	436,753.7	436,747.0	6.7
7														
8	Schedule 4 - Seasonal Service	0.762	184.6	141	439.000	16		83	-	-	-	224.1	247.9	(23.8)
9	Schedule 5 - General Firm Service	0.593	3,184.6	1,888	587.000	281		1,979	14.655	207	3,033	6,900.5	6,900.5	0.0
10														
11	Industrials													
12	Schedule 7 - Interruptible	0.990	22.7	22	880.000	2		21	-	-	-	43.6	44.0	(0.4)
13														
14	Schedule 6 - N G V Fuel - Stations	3.398	103.8	353	61.000	32		23	-	-	-	376.1	376.6	(0.5)
15														
16	Total Industrials		103.8	353		32		23		-	-	376.1	376.6	(0.5)
17														
18	Total Core Sales		113,862.9	303,578		835,964		137,666		207	3,033	444,298.0	444,316.0	(18.0)
19														
20	Transportation Service													
21	Schedule 22 - Firm Service	0.081	8,103.2	659.3	4,783.000	13		746	11.174	255.8	2,858.3	4,263.7	4,885.4	(621.7)
22	- Interruptible Service	0.739	11,080.5	8,190.3	3,742.000	22		988	-	14.5	-	9,178.2	9,078.6	99.5
23	Schedule 23 - Large Commercial	2.136	6,134.0	13,102	210.520	1,309		3,308	-	-	-	16,410.1	16,348.0	62.1
24	Schedule 25 - Firm Service	0.593	12,944.4	7,676	665.000	573		4,573	14.655	813	11,910	24,158.5	23,819.5	339.0
25	Schedule 27 - Interruptible Service	0.990	5,587.4	5,532	958.000	98		1,127	-	-	-	6,658.1	6,607.2	50.9
26														
27	Total T-Service		43,849.5	35,159		2,015		10,741		1,083	14,768	60,668.7	60,738.7	(70.0)
28														
29	Total Non-Bypass Sales & Transportation Service		157,712.4	338,737.2		837,979		148,407.4		1,290	17,800.9	504,966.7	505,054.7	(88.0)
30			(X-Ref - Tab C-13, Schedule 14)			(X-Ref - Tab C-13, Schedule 22)				(X-Ref - Tab C-13, Schedule 22 Columns 6 + 8, line 27)				

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C, Tab 13, Schedule 67

GROSS MARGIN RECONCILIATION WITH 2011 RATES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line		Proposed Base Delivery Rate			Approved Basic Charge & Admin Fee				Proposed Demand Charge			Collected	Required	Margin
No.	Particulars	Rate	Terajoules	($000)	Rate	Customers	Adj Factor	($000)	Rate	Terajoules	($000)	Margin	Margin	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	**NON-BYPASS**													
2	Core Sales													
3	Schedule 1 - Residential	3.066	68,578.9	$210,263	11.840	759,267	-1.20%	$106,586	-	-	$0	316,848.9	316,838.8	10.1
4	Schedule 2 - Small Commercial	2.557	24,603.1	62,910	24.840	77,252	-4.54%	21,981	-	-	-	84,891.4	84,899.5	(8.1)
5	Schedule 3 - Large Commercial	2.197	17,168.5	37,719	132.520	5,126	-0.51%	8,110	-	-	-	45,828.8	45,820.9	7.9
6	Total Schedules 1 , 2 and 3		110,350.5	310,892		841,644		136,677		-	-	447,569.1	447,559.2	9.9
7														
8	Schedule 4 - Seasonal Service	0.790	184.6	146	256.080	16		49	-	-	-	194.5	253.9	(59.4)
9	Schedule 5 - General Firm Service	0.611	3,184.3	1,946	587.000	281		1,979	15.134	207	3,132	7,056.8	7,061.3	(4.5)
10														
11	Industrials													
12	Schedule 7 - Interruptible	1.018	22.7	23	880.000	2		21	-	-	-	44.2	45.0	(0.8)
13														
14	Schedule 6 - N G V Fuel - Stations	3.485	103.8	362	61.000	32		23	-	-	-	385.2	385.6	(0.4)
15														
16	Total Industrials		103.8	362		32		23		-	-	385.2	385.6	(0.4)
17														
18	Total Core Sales		113,845.9	313,345		841,975		138,728		207	3,132	455,249.7	455,305.0	(55.3)
19														
20	Transportation Service													
21	Schedule 22 - Firm Service	0.083	8,103.2	675	4,783.000	13		746	11.618	256	2,972	4,393.4	4,998.4	(605.0)
22	- Interruptible Service	0.757	11,080.5	8,384	3,742.000	22		988	1.702	15	25	9,396.3	9,288.6	107.7
23	Schedule 23 - Large Commercial	2.197	6,177.2	13,571	210.520	1,318		3,331	-	-	-	16,901.9	16,845.4	56.5
24	Schedule 25 - Firm Service	0.611	12,944.1	7,909	665.000	573		4,573	15.134	813	12,299	24,780.6	24,373.3	407.3
25	Schedule 27 - Interruptible Service	1.018	5,587.4	5,688	958.000	98		1,127	-	-	-	6,814.6	6,760.2	54.4
26														
27	Total T-Service		43,892.4	36,227		2,024		10,764		1,083	15,296	62,286.9	62,265.9	21.0
28														
29	Total Non-Bypass Sales & Transportation Service		157,738.3	349,572.8		843,999		149,492.1		1,290	18,427.5	517,536.6	517,570.9	(34.3)
30			(X-Ref - Tab C-13, Schedule 15)			(X-Ref - Tab C-13, Schedule 24)					(X-Ref - Tab C-13, Schedule 24 Columns 6 + 8, line 27)			

EARNINGS SHARING CALCULATION - 2009
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Description	2009	Reference
	(1)	(2)	(3)
1	Utility rate base	$2,453,485	- Tab C-13, Schedule 74
2			
3	Common Equity Component (35.01%)	858,965	- Tab C-13, Schedule 75
4			
5			
6	Achieved ROE on Common Equity	11.41%	- Tab C-13, Schedule 75
7			
8	Authorized ROE on Common Equity	8.47%	
9			
10	ROE Surplus / (Deficit)	2.94%	
11			
12	After Tax Surplus Available for Sharing	$25,254	
13			
14			
15	Customers' 50% Share of Surplus (net-of-tax)	$12,627	(X-Ref - Tab C-13, Schedule 70)
16			
17			
18	**Customers' 50% Share of Surplus (pre-tax)**	**$18,038**	(X-Ref - Tab C-13, Schedule 70)

TERASEN GAS INC. June 15, 2009 Application Section C Tab 13 Schedule 69

END-OF-TERM CAPITAL INCENTIVE MECHANISM
FOR THE YEARS ENDING DECEMBER 31, 2004 TO 2011
($000s)

Line. No.	Particulars	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Projection 2009	2010	2011	2012	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	a) Formula Base Capital Expenditure Spending (with Actual Customer adds)										
2	Customer Addition Driven CapEx	$24,283	$26,319	$21,896	$21,441	$20,133	$13,420				
3	Other Base Capital CapEx	67,361	69,090	70,588	72,278	73,595	74,850				
4	Total Base Capital Expenditures - Formula	91,644	95,409	92,484	93,719	93,728	88,270				
5											
6	b) Actual Base Capital Expenditures										
7	Customer Addition Driven CapEx	$21,896	$25,194	$28,820	$28,903	$32,288	$25,428				
8	Other Base Capital CapEx	48,717	50,840	55,269	44,417	57,859	63,360				
9	Total Base Capital Expenditures - Actual	70,613	76,034	84,089	73,320	90,147	88,788				
10											
11	c) Capital Incentive	$21,031	$19,375	$8,395	$20,399	$3,581	($518)				
12	Cumulative Capital Incentive for Phase-Out	$21,031	$40,406	$48,801	$69,200	$72,781	$72,263				
13											
14	d) Capital Incentive @ 14%	$2,944	$5,657	$6,832	$9,688	$10,189	$10,117				
15											
16	Customer Portion (50/50 during term. Total benefit less Phase-Out after)	$1,472	$2,828	$3,416	$4,844	$5,095	$5,058	$6,745	$8,431	$10,117	
17											
18	Company Portion (50/50 during term. 2/3 & 1/3 Phase-Out in 2010 and 2011)	$1,472	$2,828	$3,416	$4,844	$5,095	$5,058	$3,372	$1,686	$0	
19											
20								(X-Ref - Tab C-13, Schedule 70)			

CALCULATION OF EARNING SHARING MECHANISM (RIDER 3)
FOR THE YEARS ENDING DECEMBER 31, 2010 TO 2011
($000s)

Line No.	Particulars	2010 Volumes (TJ)	2011 Volumes (TJ)	TOTAL Volumes (TJ)	2010 Margin ($000s)	2011 Margin ($000s)	TOTAL Margin ($000s)	2010 True-up & Res Amortization ($000s)	2010 & 2011 ESM Amortization ($000s)	2010 & 2011 Capital Incentive Amortization ($000s)	2010 ESM Unit Rider ($/GJ)	2011 ESM Unit Rider ($/GJ)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	**Earnings Sharing Mechanism (ESM) Rider 3 Calculation**											
2												
3												
4	**Non-Bypass**											
5	Rate 1 - Residential	67,829.2	67,190.5	135,019.7	$ 306,966	$ 305,757	$612,724	($304)	($7,715)	$2,232	($0.040)	($0.046)
6	Rate 2 - Small Commercial	24,374.3	24,603.1	48,977.4	82,200	82,972	165,171	(83)	(2,081)	599	($0.029)	($0.034)
7	Rate 3 / 23 - Large Commercial	22,952.6	23,345.7	46,298.3	60,218	61,243	121,461	(60)	(1,529)	441	($0.023)	($0.027)
8	Rate 4 - Seasonal Service	184.6	184.6	369.2	248	248	496	-	(6)	2	($0.011)	($0.011)
9	Rate 5 / 25 - General Firm Service	15,565.0	15,470.1	31,035.1	30,469	30,413	60,882	(30)	(767)	222	($0.017)	($0.020)
10	Rate 6 - NGV	103.8	103.8	207.6	377	377	753	-	(9)	3	($0.024)	($0.033)
11	Rate 7 / 27 - Interruptible	5,197.7	5,186.1	10,383.8	6,258	6,247	12,505	(6)	(157)	45	($0.010)	($0.012)
12	Rate 22 - Large Industrial Transportation	11,579.4	11,560.2	23,139.6	9,332	9,318	18,651	(9)	(235)	68	($0.007)	($0.008)
13	Rate 22A - Inland	4,904.7	4,904.7	9,809.4	3,920	3,920	7,841	(4)	(99)	29	($0.007)	($0.008)
14	Rate 22B - Elkview Coal	646.1	646.1	1,292.2	112	112	224	-	(3)	1	$0.000	($0.002)
15	Rate 22B - All Other	1,856.3	1,856.3	3,712.6	1,037	1,037	2,075	(1)	(26)	8	($0.005)	($0.005)
16												
17	**Total Non-Bypass**	155,193.7	155,051.2	310,244.9	$501,138	$501,645	$1,002,783	($497)	($12,627)	$3,650 [1]		
18		(X-Ref - Tab C-13, Schedule 22; - Tab C-13, Schedule 24)										

19

20 Note 1:
21 Terasen Gas is projecting a 2009 return on equity of 11.41%, which is 2.94% higher than
22 the allowed ROE of 8.47%. Under the earnings sharing mechanism, Terasen Gas is to share
23 equally with its customers, earnings variances between the authorized level of earnings as
24 determined annually under the settlement and the actual earnings of the utility. Accordingly,
25 customer's portion of the 2009 earnings surplus is $18.038 million. The detailed calculations
26 for 2009 are as follows:
27
28 After Tax surplus available for sharing = $858.965 million x (11.41% - 8.47%) = $25,254 million
29 Customers' 50% share (Net-of-Tax) = $12.627 million
30 Customers' 50% share (Pre-Tax) = $18.038 million

Line		Amortization Period	2010 Pre-Tax	2010 Net-Of-Tax	2011 Pre-Tax	2011 Net-Of-Tax	Total Pre-Tax	Total Net-Of-Tax	
32	The total amortization balance of $13.690 is made up of:								
33	2008 true-up ($12.029m per '07 A/Review, $12.739m per '08 A/Rpt)	2011	$710	$508	$0	$0	$710	$508	
34	Tax Adjustment on 2008 ESM True Up		(15)	(11)			(15)	(11)	
35			695	497	-	-	695	497	(Column 8, Line 17)
36									
37	2009 pre-tax Customers' 50% share	2010 and 2011	9,036	6,461	9,003	6,617	18,039	13,078	
38	Tax Adjustment on 2009 ESM		(190)	(136)	(429)	(315)	(618)	(451)	(Column 9, Line 17)
39			8,846	6,325	8,574	6,302	17,420	12,627	(X-Ref - Tab C-13, Schedule 68)
40									
41	2009 End Of Term Capital Incentive Mechanism	2010 and 2011	(3,372)	(2,411)	(1,686)	(1,239)	(5,058)	(3,650)	(Column 10, Line 17)
42									(X-Ref - Tab C-13, Schedule 69)
43	Total Balance - Refund to Customers in 2010 and 2011		$6,169	$4,411	$6,888	$5,063	$13,057	$9,474	(X-Ref - Tab C-13, Schedule 54; Schedule 55 line 39, columns 8 & 9)

CALCULATION OF AMORTIZATION OF RSAM (RIDER 5)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Particulars (1)	2010 Volumes (TJ) (2)	2011 Volumes (TJ) (3)	2010 Amortization ($000s) (4)	2011 Amortization ($000s) (5)	2010 Amortization of RSAM Unit Rider ($/GJ) (6)	2011 Amortization of RSAM Unit Rider ($/GJ) (7)
RSAM (Rider 5) Calculation						
Rate 1 - Residential	67,829.2	67,190.5			($0.053)	($0.052)
Rate 2 - Small Commercial	24,374.3	24,603.1			($0.053)	($0.052)
Rate 3 - Large Commercial	16,818.6	17,168.5			($0.053)	($0.052)
Rate 23 - Large Commercial Transportation	6,134.0	6,177.2			($0.053)	($0.052)
	115,156.1	115,139.3	($6,156)	($5,990) (1)		

(X-Ref - Tab C-13, Schedule 54; - Tab C-13, Schedule 55,sum of lines 6 & 7 and columns 8 & 9)

Note 1: RSAM Rider Change

Terasen Gas forecasts that there will be approximately -$5.6 million (net-of-tax) of RSAM additions by the end of 2009. After offsetting the 2009 RSAM Rider recovery, the RSAM account including interest is now projected to be a credit balance of $13,204,000 on a net-of-tax basis by the end of 2009. In accordance with the 2004-2009 Extended PBR Settlement, the RSAM balance is to be amortized over three years. Accordingly, the net-of-tax RSAM balance to be amortized in 2010 is a credit of $4,402,000. On a pre-tax basis, this amounts to $6,156,000 or a refund to the customer of $0.053/GJ, which is a $.054 reduction from the existing charge of $0.001/GJ. The corresponding 2011 refund to the customer is $0.052/GJ.

2010 Net-Of-Tax Amortization = 1/3 of Projected December 31, 2009 RSAM Balance
= 1/3 * ($-13,166 RSAM + $-38 RSAM Interest)
= 1/3 * $-13,204
= $-4,402 Net-of-tax amortization

2010 Pre-Tax Amortization = Net-of-tax amortization / (1 - tax rate) + Amortization on Prior years' balances
= $-4,402 / (1 - 28.5%)
= $-6,156

2011 Net-of-Tax Amortization = 1/2 of Projected December 31, 2010 RSAM Balance
= 1/2 * ($-8,777 RSAM + $-29 RSAM Interest)
= 1/2 * $-8,806
= $-4,402 Net-of-tax amortization

2011 Pre-Tax Amortization = Net-of-tax amortization / (1 - tax rate) + Amortization on Prior years' balances
= $-4,402 / (1 - 26.5%)
= $-5,990

TERASEN GAS INC. June 15, 2009 Application Section C
Tab 13
Schedule 72

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Existing 2009 Rates	----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	108,575	115,723	-	115,723	7,148	
3	Transportation	85,478	89,214	-	89,214	3,736	
4		194,053	204,937	-	204,937	10,884	
5							
6	Average Rate per GJ						
7	Sales	$14.892	$11.902	$0.000	$11.902	($2.990)	
8	Transportation	$0.848	$0.830	$0.000	$0.830	($0.018)	
9	Average	$8.706	$7.000	$0.000	$7.000	($1.706)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,591,039	$1,377,376	$0	$1,377,376	($213,663)	
13	- Increase / (Decrease)	25,852	-	-	-	(25,852)	
14	RSAM Revenue		(17,004)	-	(17,004)	(17,004)	
15	Transportation - Existing Rates	68,993	74,087	-	74,087	5,094	
16	- Increase / (Decrease)	3,535		-	-	(3,535)	
17	**Total**	1,689,419	1,434,459	-	1,434,459	(254,960)	
18							
19	Cost of Gas Sold (Including Gas Lost)	1,187,999	931,546	-	931,546	(256,453)	
20							
21	**Gross Margin**	501,420	502,913	-	502,913	1,493	
22							
23	Operation and Maintenance	173,138	165,162	-	165,162	(7,976)	- Tab C-13, Schedule 28
24	Vehicle Lease	1,804	1,804	-	1,804	-	- Tab C-13, Schedule 28
25	Property and Sundry Taxes	47,593	47,593	-	47,593	-	- Tab C-13, Schedule 31
26	Depreciation and Amortization	89,685	79,725	-	79,725	(9,960)	- Tab C-13, Schedule 33
27	Other Operating Revenue	(23,444)	(20,906)	-	(20,906)	2,538	- Tab C-13, Schedule 26
28		288,776	273,378	-	273,378	(15,398)	
29	Utility Income Before Income Taxes	212,644	229,535	(1)	229,535	16,891	
30							
31	Income Taxes	26,331	23,010	1	23,010	(3,321)	
32							
33	**EARNED RETURN**	$186,313	$206,525	$0	$206,525	$20,212	(X-Ref - Tab C-13, Schedule 73)
34							
35							
36	**UTILITY RATE BASE**	$2,541,358	$2,453,485	$0	$2,453,485	($87,873)	- Tab C-13, Schedule 74
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.33%	8.42%		8.42%	1.09%	

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Existing 2009 Rates	----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$186,313	$206,525	$0	$206,525	$20,212	- Tab C-13, Schedule 72
3	Deduct - Interest on Debt	(110,953)	(108,525)	-	(108,525)	2,428	- Tab C-13, Schedule 75
4	Add- Non-Tax Ded. Expense (Net)	328	428	-	428	100	
5							
6	Accounting Income After Tax	75,688	98,428	-	98,428	22,740	
7	Add (Deduct) - Timing Differences	(14,248)	(44,736)	-	(44,736)	(30,488)	- Tab C-13, Schedule 37
8							
9	Taxable Income After Tax	$61,440	$53,692	$0	$53,692	($7,748)	
10							
11		30.000%	30.000%	30.000%	30.000%	0.000%	
12	1 - Current Income Tax Rate	70.000%	70.000%	70.000%	70.000%	0.000%	
13							
14	Taxable Income	$87,771	$76,703	$0	$76,703	($11,068)	
15							
16	**Total Income Tax**	$26,331	$23,011	$0	$23,011	($3,320)	
17							

TERASEN GAS INC. June 15, 2009 Application Section C Tab 13 Schedule 74

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Existing 2009 Rates	2009 Adjustments	2009 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,339,098	$3,215,664	$0	$3,215,664	($123,434)	
2	Adjustment - CPCNs	12,855	12,879	-	12,879	24	
3	Gas Plant in Service, Ending	3,442,274	3,317,590	-	3,317,590	(124,684)	- Tab C-13, Schedule 45
4							
5	Accumulated Depreciation Beginning - Plant	($808,588)	($743,486)	$0	($743,486)	$65,102	
6	Accumulated Depreciation Ending - Plant	(869,177)	(779,187)	-	(779,187)	89,990	- Tab C-13, Schedule 49
7							
8	CIAC, Beginning	($148,423)	($161,636)	$0	($161,636)	($13,213)	
9	CIAC, Ending	(146,828)	(176,845)	-	(176,845)	(30,017)	- Tab C-13, Schedule 52
10							
11	Accumulated Amortization Beginning - CIAC	$46,175	$45,381	$0	$45,381	($794)	
12	Accumulated Amortization Ending - CIAC	44,846	44,146	-	44,146	(700)	- Tab C-13, Schedule 52
13							
14	Net Plant in Service, Mid-Year	$2,456,116	$2,387,253	$0	$2,387,253	($68,863)	
15							
16							
17	Adjustment to 13-Month Average	-	(10,554)	-	(10,554)	(10,554)	
18	Work in Progress, No AFUDC	15,773	15,627	-	15,627	(146)	
19	Unamortized Deferred Charges*	(32,644)	(25,545)	-	(25,545)	7,100	- Tab C-13, Schedule 76
20	Cash Working Capital	(33,719)	(27,183)	-	(27,183)	6,536	- Tab C-13, Schedule 56
21	Other Working Capital (incl. Construction Advances)	138,198	115,701	-	115,701	(22,497)	- Tab C-13, Schedule 56
22	Future Income Taxes Regulatory Asset	-	278,048	-	278,048	278,048	- Tab C-13, Schedule 61
23	Future Income Taxes Regulatory Liability	(552)	(278,048)	-	(278,048)	(277,496)	- Tab C-13, Schedule 61
24	LILO Benefit	(1,814)	(1,814)	-	(1,814)	-	
25	**Utility Rate Base**	$2,541,358	$2,453,485	$0	$2,453,485	($87,873)	(X-Ref - Tab C-13, Schedule 68, Schedule 72,Schedule 75)

*Not equal to Schedule 8, column (2), line 19 because of differences in MCRA, CCRA and ESM balances for ESM calculation purposes

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	Reference	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2009 RATES							
2	Long-Term Debt			$1,504,299	62.36%	6.959%	4.34%	
3	Unfunded Debt			90,221	2.63%	4.250%	0.11%	
4	Preference Shares			-	0.00%	0.000%	0.00%	
5	Common Equity			858,965	35.01%	11.740%	4.11%	
6								
7		- Tab C-13, Schedule 74		$2,453,485	100.00%		8.56%	
8								
9	2009 REVISED RATES							
10	Long-Term Debt			$1,504,299	61.31%	6.959%	4.27%	$104,691
11	Unfunded Debt		$90,221					
12	Adjustment, Revised Rates		-	90,221	3.68%	4.250%	0.16%	3,834
13	Preference Shares			-	0.00%	0.000%	0.00%	-
14	Common Equity			858,965	35.01%	11.409%	3.99%	97,999
15		(X-Ref - Tab C-13, Schedule 72)						
16		- Tab C-13, Schedule 74		$2,453,485	100.00%		8.42%	$206,525

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	Balance 12/31/2008	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2009	Mid-Year Average 2009
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Margin Related									
2	Commodity Cost Reconciliation Account (CCRA)	($23,164.7)	$602.9	($180.9)	$422.0	$0.0	$0.0	$0.0	($22,742.7)	($22,953.7)
3	CCRA Interest	(596.2)	(428.2)	128.5	(299.7)	-	-	-	(895.9)	(746.1)
4	Midstream Cost Reconciliation Account (MCRA)	(23,588.7)	85,731.4	(25,719.4)	60,012.0	-	-	-	36,423.3	6,417.3
5	MCRA Interest	(1,812.2)	47.2	(14.2)	33.0	-	-	-	(1,779.2)	(1,795.7)
6	Revenue Stabilization Adjustment Mechanism (RSAM)	(7,917.2)	(7,902.9)	2,370.9	(5,532.0)	-	405.1	(121.5)	(13,165.6)	(10,541.4)
7	RSAM Interest	35.3	(133.2)	40.0	(93.2)	-	27.8	(8.3)	(38.4)	(1.6)
8	Revelstoke Propane Cost Deferral Account	(477.8)	627.1	(188.1)	439.0	-	-	-	(38.8)	(258.3)
9	SCP Mitigation Revenues Variance Account	(4,539.0)	(981.7)	324.5	(657.2)	1,078.1	-	-	(4,118.1)	(4,328.6)
10	SCP West to East Transmission	(1,658.0)	(376.1)	124.7	(251.4)	371.2	-	-	(1,538.2)	(1,598.1)
11										
12	Energy Policy Related									
13	Energy Efficiency & Conservation (EEC)	1,205.0	8,002.0	(2,400.6)	5,601.4	(436.2)	-	-	6,370.2	3,787.6
14	NGV Conversion Grants	124.0	80.0	(24.0)	56.0	(43.1)	-	-	136.9	130.5
15										
16	Non-Controllable Items									
17	Property Tax Deferral	(732.0)	(700.0)	210.0	(490.0)	478.2	-	-	(743.8)	(737.9)
18	Insurance Variance	(259.0)	(479.5)	143.9	(335.6)	(91.4)	-	-	(686.0)	(472.5)
19	Pension & OPEB Variance	207.0	(581.4)	-	(581.4)	(312.0)	-	-	(686.4)	(239.7)
20	BCUC Levies Variance	(295.0)	(383.7)	115.1	(268.6)	301.6	-	-	(262.0)	(278.5)
21	Interest Variance	(1,629.0)	(790.1)	237.0	(553.1)	(50.1)	-	-	(2,232.2)	(1,930.6)
22	Interest Variance - Funding benefits via Customer Deposits	161.0	76.9	(23.1)	53.8	(0.6)	-	-	214.2	187.6
24	Olympics Security Costs Deferral	-	746.9	(224.1)	522.8	-	-	-	522.8	261.4
25	IFRS Conversion Costs	98.0	430.7	(129.2)	301.5	-	-	-	399.5	248.8
26										
27	Cost of Current Applications									
28	2009 ROE & Cost of Capital Application	$0.0	$630.0	($189.0)	$441.0	$0.0	$0.0	$0.0	$441.0	$220.5
29	2010-2011 Revenue Requirement Application	55.0	1,057.5	(317.3)	740.2	-	-	-	795.2	425.1
30	CCE CPCN Application	-	270.0	(81.0)	189.0	-	-	-	189.0	94.5
31										-
32	Other									-
33	IFRS Transitional Adjustments	-	-	-	-	-	-	-	-	-
34	OPEB Funding	(28,644.0)	(5,582.6)	1,674.8	(3,907.8)	-	-	-	(32,551.8)	(30,597.9)
35	Pension & OPEB Funding	-	-	-	-	-	-	-	-	-
36										-
37	Residual Deferred Charges									-
38	SCP Tax Reassessment	7,292.8	165.0	(49.5)	115.5	-	-	-	7,408.3	7,350.6
39	Deferred Service Line Installation Fee	-	1,442.9	-	1,442.9	-	-	-	1,442.9	1,442.9
40	Earnings Sharing Mechanism	(9,879.1)	(18,748.0)	5,624.4	(13,123.6)	-	14,113.0	(4,233.9)	(13,123.6)	(11,501.4)
41	CCT Assessment	(16.0)	-	-	-	13.5	-	-	(2.5)	(9.3)
42	Carbon Tax Implementation	103.0	-	-	-	(198.0)	-	-	(95.0)	4.0
43	TGS Amalgamation	132.0	-	-	-	-	-	-	132.0	132.0
44	TGS O&M Variance	233.0	170.0	(51.0)	119.0	-	-	-	352.0	292.5
45	Carbon Tax Cost of Service	(384.0)	326.0	(97.8)	228.2	111.8	-	-	(44.0)	(214.0)
46	OSC Certification Compliance	90.0	110.7	(33.2)	77.5	(76.4)	-	-	91.1	90.6
47	Bad Debt Allowance for Rates 14 & 14A	(114.0)	(26.6)	0.4	(26.2)	-	-	-	(140.2)	(127.1)
48	2005 ROE Hearing	150.0	-	-	-	(150.0)	-	-	-	75.0
49	2006 LCT Elimination	14.0	-	-	-	(14.0)	-	-	-	7.0
50	NGV Compression Equipment Recovery	249.0	-	-	-	(249.0)	-	-	-	124.5
51	SCP PG&E Contract Cancellation	661.8	-	-	-	(661.8)	-	-	-	330.9
52										
53										
54	Total Deferred Charges for Rate Base	($94,895.0)	$63,403.2	($18,728.2)	$44,675.0	$71.8	$14,545.9	($4,363.7)	($39,966.0)	($66,709.1)
55										
56	Reconciliation with Mid Year Deferred Charges for ESM calculation:									
57										
58	Less:			Add:						
59	Projected Mid Year MCRA balance (+ interest)	4,621.6		Approved Mid Year MCRA balance (+ interest)				7,961.3		
60	Projected Mid Year CCRA balance (+ interest)	(23,699.8)		Approved Mid Year CCRA balance (+ interest)				(12,224.5)		
61	Projected Mid Year Revelstoke Propane balance	(258.3)		Approved Mid Year Revelstoke Propane balance				16.7		
62	Projected Mid Year ESM balance	(11,501.4)		Approved Mid Year Approved balance				3,916.2		
63	Projected Mid Year RSAM balance (+ interest)	(10,543.0)	(41,380.9)	Approved Mid Year RSAM balance (+ interest)				113.7	(216.6)	
64										
65					Net Mid-Year Reconciling items for ESM purposes					41,164.3
66					Mid Year Deferred Charges balance for ESM purposes					($25,544.8)
67										(X-Ref - Tab C-13, Schedule 74)
68										

Terasen Gas Inc. 2010-2011 Revenue Requirements Application
Negotiated Settlement Process
Issues of Particular Concern to the Commission Panel

In accordance with sections 3 and 9 of the Negotiated Settlement Process-Policy, Procedures and Guidelines, the Commission Panel has identified the following issues of particular concern that parties should be aware of during the negotiations:

1. EEC Program-TGI is to provide results of the programs approved by the EEC Decision and expectations for new programs before the Commission Panel will approve additional EEC program funding.

2. Natural Gas for Vehicles ("NGV")-if NGV is to proceed why should the natural gas ratepayer fund this initiative rather than Terasen's non-regulated businesses or the competitive market?

3. Biogas-to be reviewed by a CPCN which demonstrates market uptake of customers that are willing to pay the full cost.

4. International Financial Reporting Standards ("IFRS")-no IFRS impact in 2010.

5. 2010 Rate Changes-in the event that a 2010 rate reduction were to occur as a result of the negotiations, the current rates should remain unchanged and place the revenue surplus into a deferral account to apply against 2011 and future rate increases with a phase in amortization that strives for rate stability.

6. CPCN threshold-stay at $5million.

7. Unrealized losses in rate base-should some of these losses be to the shareholder? Parties should present a separate settlement package.

The
British Columbia
Public Interest
Advocacy Centre

208–1090 West Pender Street
Vancouver, BC V6E 2N7
Coast Salish Territory
Tel: (604) 687-3063 Fax: (604) 682-7896
email: bcpiac@bcpiac.com
http://www.bcpiac.com

Valerie Conrad	687-3017
Sarah Khan	687-4134
Eugene Kung	687-3006
James L. Quail	687-3034
Ros Salvador	488-1315
Leigha Worth	687-3044

Barristers & Solicitors

Peggy Lee
Article Student

Our file: 7432

November 12, 2009

VIA EMAIL

Erica M. Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Re: Terasen Gas Inc. Revenue Requirements 2010-2011
Negotiated Settlement

This is to confirm that we are satisfied that the draft Settlement Agreement circulated by Mr. Thompson and Mr. Loski on November 5, 2009 accurately captures the consensus reached by the parties to the Negotiated Settlement Process in this proceeding, and that we have been instructed by our clients, BCOAPO et al., to endorse it.

Accordingly, we ask that the Commission incorporate it into a consent Order for the resolution of all issues in the Application.

Our only further comments, made here only "for the record" and in no way detracting from our clients' endorsement of the Settlement, concern the “Alternative Energy Solutions" addressed under heading 13 of the document. While we believe that the ultimately appropriate corporate and regulatory formats for these lines of business are subject-matters which may require eventual determination by the Commission, our clients are content with the treatment of these issues in the Settlement Agreement over its term, in that it provides a “firewall” to ensure that the utility’s natural gas distribution customers do not subsidize or otherwise contribute to these nascent programs through their rates.

Yours truly,

BC PUBLIC INTEREST ADVOCACY CENTRE

Original in file signed by:

Jim Quail
Executive Director

cc: parties of record

OWEN • BIRD
LAW CORPORATION

PO Box 49130
Three Bentall Centre
2900-595 Burrard Street
Vancouver, BC
Canada V7X 1J5

Telephone 604 688-0401
Fax 604 688-2827
Website www.owenbird.com

Direct Line: 604 691-7557
Direct Fax: 604 632-4482
E-mail: cweafer@owenbird.com
Our File: 23841/0040

November 13, 2009

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C. V6Z 2N3

Attention: Erica M. Hamilton,
Commission Secretary

Dear Sirs/Mesdames:

Re: Terasen Gas Inc. ("Terasen") 2010 and 2011 Revenue Requirements and Delivery Rates Application, Project No. 3698562

We are counsel to the Commercial Energy Consumers Association of British Columbia (the "CEC"). We confirm that the CEC accepts the terms of the final version of the Negotiated Settlement Agreement on the above-noted Application circulated by Terasen on November 5, 2009 and have no comments on that draft.

The CEC thanks the Commission staff and facilitator, Terasen and the other customer representatives for their efforts during these negotiations.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jlb
cc: CEC
cc: Terasen
cc: Registered Intervenors

November 13, 2009

Mr. Philip Nakoneshny
Director of Rates and Finance
British Columbia Utilities Commission

RE: Negotiated Settlement Terasen Gas Inc. (TGI) Revenue Requirements Settlement 2010/2011

Dear Mr. Nakoneshny:

On November 5, 2009, TGI forwarded a Draft Agreement and requested that edits and comments be forwarded to TGI. Ministry of Energy, Mines and Petroleum Resources staff have reviewed the Draft Agreement and from a policy perspective, have an interest in 5 items:

11. Energy Efficiency and Conservation ("EEC") Funding for 2010
12. EEC Funding for 2011
13. Alternative Energy Solutions
14. Natural Gas for Vehicles
15. Biogas

Other components of the negotiated settlement such as capital cost structure, interest rates, depreciation rates, salvage values, etc., are outside the purview of the Ministry's interests in this agreement. However, we note that, in the future, Use per Customer Rates (8) and Industrial Demand Forecast (9) may be lower depending on the implementation of TGI's EEC programs.

The 2007 Energy Plan and Climate Action Plan, 2008 amendments to the *Utilities Commission Act,* Ministerial Order B.C. Reg. 326/2008, and the Ministry's involvement in the 2008/09 TGI/TGVI Energy Efficiency and Conservation Application indicate the Province's intent to require electric and natural gas utilities to pursue energy efficiency.

The Ministry is particularly pleased with the reallocation of funds for low income and rental housing programs to $2.4 million for 2010 and 2011. The Ministry also appreciates the increase in industrial energy efficiency program funding in 2011.

.../2

We believe there is great potential for a significant amount of this industrial funding to be applied collaboratively with existing demand side management programs at electric utilities, especially at BC Hydro, in order to minimize duplication of structural costs and to maximize energy savings benefits at industrial facilities.

Appropriate oversight of EEC funding is maintained through the TRC requirements and annual reporting to the Commission. As a result, the Ministry supports Option 12.1 (a) and (b) to maintain program continuity and effectiveness.

Alternative Energy Solutions is a new type of service that TGI proposes to offer to existing and new customers. Geo-exchange, solar-thermal and district energy systems offer the potential to reduce greenhouse gas emissions, and as such, the Ministry is encouraged that TGI is proposing to offer this new type of service.

The Ministry supports the expanded use of natural gas for vehicles (NGV) and biogass, and is encouraged that TGI intends to apply to the Commission for appropriate rates.

Sincerely,

Paul Wieringa
Executive Director
Renewable Energy and Energy Efficiency Branches
Ministry of Energy, Mines and Petroleum Resources
Telephone: 250-952-0243
Facsimile: 250-952-0258

From: Nakoneshny, Philip BCUC:EX
Sent: Friday, November 13, 2009 12:59 PM
To: Commission Secretary BCUC:EX
Subject: FW: Terasen Gas -Revenue Requirements-Negotiated Settlement

-----Original Message-----
From: Dave Newlands [mailto:dnewlands@telus.net]
Sent: Friday, November 13, 2009 9:40 AM
To: 'Al Kleinschmidt'; Brownell, Bob BCUC:EX; Bystrom, Chris; Chris Weafer; J. David Newlands; Roy, Diane; David Craig (dwcraig@allstream.net); Domingo, Yolanda BCUC:EX; Stout, Douglas; 'Eugene Kung'; 'Frederick Metcalfe'; 'Leigha Worth'; McMahon, Claudia BCUC:EX; Carman, Michelle; Nakoneshny, Philip BCUC:EX; 'Paul Cassidy'; Hill, Shawn; Loski, Tom; Wieringa, Paul EMPR:EX; Ghikas, Matt; Sue, Suzanne BCUC:EX; Thomson, Scott - TGI; James L. Quail (JimQuail@bcpiac.com)
Cc: Bernadet Mark SPO
Subject: Terasen Gas -Revenue Requirements-Negotiated Settlement

Philip Nakoneshny
Director of Rates and Finance
British Columbia Utilities Commission

Dear Philip

Terasen Gas Revenue Requirements Application-2010/2011
Negotiated Settlement

I write on behalf of Teck Coal.

Teck Coal participated in the Negotiated Settlement Process ("NSP"),facilitated by the Staff of the British Columbia Utilities Commission, and held in the offices of the Commission ,which commenced on October 21,2009.

Teck Coal in the negotiations took into consideration the 7 "Issues of Particular Concern to the Commission Panel ",as provided by the Commission Panel at the commencement of the negotiation.

Issue Number 5 stated " 2010 Rate Changes- in the event that a 2010 rate reduction were to occur as a result of the negotiations ,the current rates should remain unchanged and place the revenue surplus into a deferred account to apply against 2011 and future rate increases with a phase in amortization that strives for rate stability"

Teck Coal supports the Negotiated Settlement Agreement Package ("TGI NSP Agreement Package ") dated and circulated by Terasen Gas Inc incorporating a decrease of (1.73%) in the Fiscal Year commencing January 1,2010,previously an increase of 5.3%.and an increase of 3.93% in the Fiscal Year Commencing January 1,2011,previously an increase of 4.1% .

The Negotiated Settlement Agreement Package, incorporates ,amongst others,Issues of Particular Concern to the Commission Panel No. 5

Teck Coal recognizes and emphasizes that this Agreement is the product of compromise on the part of all Parties, yielding an overall package that the Parties consider to be fair, just and reasonable. The Parties agreed that any compromises resulting from this Agreement are without prejudice to the Parties¹ ability to take different positions after 2011 and without prejudice to the Parties right to intervene in any applications contemplated in or resulting from this Agreement.

Yours Truly

J.David Newlands

Cc Mark Bernadet ,General Manager ,Business Improvement,Teck Coal

BRITISH COLUMBIA UTILITIES COMMISSION

PHILIP W. NAKONESHNY
DIRECTOR, RATES AND FINANCE
Philip.Nakoneshny@bcuc.com
web site: http://www.bcuc.com

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

November 13, 2009

Erica M. Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: Terasen Gas Inc.
2010 and 2011 Revenue Requirements Application
Negotiated Settlement Agreement
Letter of Comment

Commission staff participated in the settlement discussions that led to a Negotiated Settlement Agreement ("Settlement Agreement") being reached between Terasen Gas Inc. ("Terasen Gas") and the registered Intervenors (collectively, the "Parties") in accordance with the *Negotiated Settlement Process-Policy, Procedures and Guidelines, January 2001* ("NSP Guidelines"). Commission staff has informed the Parties that the agreements reached on certain issues were not supported by Commission staff and that Commission staff intended to submit a Letter of Comment in respect of those issues. The Parties agreed to Commission staff adopting that course.

There are three items in the Settlement Agreement that Commission staff do not support:

1. Item 10-Inclusion of SCP Capacity in MCRA

Commission Order G-98-05 states that:

"The Commission approves the debiting of the annual charge of $3.6 million (based on the monthly instalments) against the Midstream Cost Reconciliation Account, with an equal and offsetting amount to be credited to the delivery margin the revenue account for a limited period as a unique and unusual transaction in the circumstances of the SCP and the termination of the BC Hydro TSA. The debiting and the crediting will commence on either November 1, 2005 or January 1, 2006, as consistent with the amount of the BC Hydro/Terasen Inc. TSA revenue that Terasen Gas forecast in its Annual Review submission for 2005 and will end on the earlier of the November 1, 2010 or such other date as the Commission may determine."

The Settlement Agreement continues to include the annual charge of $3.6 million against the MCRA with an offsetting credit to the delivery margin. In Commission staff's view, extending this treatment beyond November 1, 2010 as contemplated by Order G-98-05 requires a determination by the Commission Panel.

Commission staff accepts that such determination will occur if the Commission Panel approves the Settlement Agreement.

2. Item 13-Alternative Energy Solutions

Terasen Gas added 9 enhanced sales and business development staff in 2009 estimated to cost $1.35 million and proposes increases of $3.0 million in 2010 for an additional 10 enhanced sales and business development staff including $1.1 million for consultants and studies and a further $0.6 million in 2011 for 4 enhanced sales and business development staff (BCUC IR 1.72.2 and IR 2.96.2 to 2.96.4; IR 1.114.7). The number of customers are expected to increase between 1.0 to 1.1 percent from 2009 to 2011, but the level of spending in Customer Solutions and Services increases by 17 percent, 27 percent and 8 percent respectively from 2009 to 2011 (BCUC IR 1.96.3).

The New Energy Solutions Deferral Account is to capture direct costs, sales and marketing O&M and other development costs by timesheets or other direct charge and an overhead allocation. In Commission staff's view, due to the modest growth in customer additions from 2009 to 2011, the additional enhanced sales and business development staff were primarily hired in 2009 to 2011 to develop and market Alternative Energy Solutions. The use of timesheets, direct charges and overhead allocations may result in a proper reallocation of costs from the gas utility to the New Energy Solutions Deferral Account.

The down time or idle time that will likely be experienced while the Alternative Energy is being marketed may not be captured by the timesheet allocation and could remain as a cost to the gas utility. In Commission staff's view, it would be preferable to directly charge the fully loaded cost of the additional enhanced sales and business development staff and the costs of consultants and studies to the New Energy Solutions Deferral Account to avoid any of these costs being borne by natural gas customers.

If Terasen Gas is able to demonstrate that the use of timesheets, direct charges and overhead allocations would result in none of the costs that are incurred for Alternative Energy Solutions including down time and the costs of consultants and studies to be borne by gas customers, then Commission staff's concern is addressed.

3. Item 14-Natural Gas for Vehicles ("NGV")

Terasen Gas proposes to treat as general O&M, rather than track separately, NGV marketing and project development costs incurred prior to signing a contract with a customer for compression and refuelling service (BCUC IR 1.21.1).

Commission staff attempted to obtain information on the NGV marketing costs that are currently incurred through information requests, but were unsuccessful. In Commission staff's view, information on the incremental marketing costs being incurred will be required if Terasen Gas, during 2010 and 2011, applies for approval of Rate Schedule 6 C NGV Compression and Refuelling Service and 6A NGV Refuelling Service , including recovery of the incremental marketing costs, and the Commission is to review the applications on a case-by-case basis as contemplated in the Settlement Agreement.

Yours truly,

Original Signed by

Philip W. Nakoneshny
Director, Rates and Finance

Terasen Gas

Tom A. Loski
Chief Regulatory Officer

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 592-7464
Cell: (604) 250-2722
Fax: (604) 576-7074
Email: tom.loski@terasengas.com
www.terasengas.com

Regulatory Affairs Correspondence
Email: regulatory.affairs@terasengas.com

November 13, 2009

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

Attention: Mr. Philip Nakoneshny, Director, Rates and Finance

Dear Mr. Nakoneshny:

Re: Terasen Gas Inc. ("Terasen Gas")
2010 and 2011 Revenue Requirements Application
Negotiated Settlement Agreement

On June 15, 2009, Terasen Gas filed its 2010 and 2011 Revenue Requirements Application, which was supplemented by a filing on July 9, 2009 and amended by filings on August 14 and September 18, 2009 (the "Application").

In accordance with Commission Order No. G-76-09 issued on June 19, 2009, a Workshop was held on July 6, 2009 for a review of the Application, a Procedural Conference was held on July 15, 2009, and Terasen Gas responded to two rounds of Information Requests. In accordance with Commission Order No. G-89-09 issued on July 20, 2009, a second Procedural Conference was held on September 25, 2009 and on October 2, 2009, the Commission issued Order G-119-09 establishing a Negotiated Settlement Process ("NSP") for the Application. In accordance with Order No. G-120-09, the NSP commenced on Wednesday, October 21, 2009 and concluded on Wednesday, November 4, 2009.

Terasen Gas has reviewed the attached settlement documents, including the Negotiated Settlement Agreement and associated financial schedules (collectively the "Negotiated Settlement") arising from the NSP. Terasen Gas recognizes the Negotiated Settlement as being the product of good faith compromises among parties with diverse interests in the issues raised by the Application. The Parties have expressly considered the Commission Panel's Issues. In fulfilling their role pursuant to the Commission's Negotiated Settlement Process Policy, Procedures and Guidelines (the "Guidelines"), Commission Staff made additional information available to the parties which they believed was in the public interest. The parties considered all such information in reaching the compromise Settlement Agreement and Terasen Gas considers the resulting Negotiated Settlement to be fair, just and reasonable. As the Negotiated Settlement represents compromises among the parties and an overall balance of interests, Terasen Gas stresses that the Negotiated Settlement should be considered as a package, with no part being severed unless otherwise stated in the Agreement. On that basis, Terasen Gas accepts the Negotiated Settlement.

Commission Staff have provided written comment on the NSP, and TGI responds to those comments below.

Inclusion of Southern Crossing Pipeline ("SCP") Capacity in the Midstream Cost Reconciliation Account ("MCRA"): TGI notes for reference that the evidence on the inclusion of the SCP costs in the MCRA is found in the Application on pages 314 to 315 and its response to BCUC IRs 1.68.1 and 2.92.1-7. The result of taking the approach in the Agreement is a lower delivery rate, all else equal, with an offsetting charge to the MCRA.

Alternative Energy Solutions (Geothermal/District Energy Systems and Solar Thermal): Staff's position on this issue turns on its view that, *"due to the modest growth in customer additions from 2009 to 2011, the additional enhanced sales and business development staff were primarily hired in 2009 to 2011 to develop and market Alternative Energy Solutions."* While that may be Staff's position, it is at odds with TGI's evidence. Staff's conclusion appears to rest on the notion that TGI could not truly require additional staff for marketing if there is only modest growth in customer additions, i.e. that there is a linear correlation between marketing effort and customer additions. TGI's evidence was that the competitive factors facing the gas business mean that it is necessary to invest more to maintain and grow the business, including the gas business.

Staff also identifies an issue relating to overhead allocation to the alternative energy class of service, so as to ensure gas customers are not bearing costs attributable to the pursuit of geothermal, solar thermal and district energy systems. The cost allocation methodology outlined in the Agreement is structured to avoid cross subsidization by gas customers. The Agreement contemplates a $500,000 annual overhead allocation to alternative energy solutions, and a corresponding reduction in overhead allocated to gas customers. This is a direct benefit to gas customers. As a point of comparison, the allocation of overhead to alternative energy solutions is approximately two times the allocation to Terasen Gas (Whistler) Inc., suggesting that the issue of overhead allocation is addressed adequately. The risk of non-recovery lies with TGI's shareholder, not gas customers. Notably, the gas customers themselves have endorsed the Agreement.

NGV Marketing Costs: TGI notes that it has an existing NGV tariff and the amount of NGV marketing costs in the revenue requirements for 2010 and 2011 is very modest (see TGI's responses to BCUC IR 1.21.2 (last paragraph) and BCUC IR 2.96.2). Issues relating to NGV have been deferred by the terms of the Settlement Agreement. TGI respectfully submits that there is no need for the Panel to address Staff's issue at this time.

TGI wishes to make one final comment relating to our procedural concerns regarding the publication of Staff's comments. Commission Staff unquestionably plays an important role during the confidential settlement discussions in providing information and assisting the parties, and providing a perspective regarding their view on the public interest. That role is one sanctioned by, and described in, the Commission's Guidelines. However, under the Guidelines (at page 8) Commission Staff is precluded from, "endorsing a particular position". TGI therefore questions whether the letter provided by Commission Staff is consistent with the Guidelines.

TGI respectfully submits that the requirement for the Commission Staff not to take positions on issues makes good sense. Commission Staff is not a party to the resulting Agreement; rather, the Negotiated Settlement Agreement is simply an agreement among intervenors and the applicant that a certain outcome is acceptable to them and should be jointly submitted for consideration by the Panel. In this case, the Agreement is clear that the Parties, having fully considered the information provided by Staff during the course of the NSP, have reached a compromise agreement that they consider to be in all respects fair, just and reasonable. As is inherent in every compromise, there will be outcomes about which a particular party was only supportive in exchange for other concessions. By commenting on the Agreement reached, Commission Staff places the parties in the position of having to justify individual items without being able to detail the steps that led to the outcome (which would not be appropriate in any event). It similarly places focus on isolated issues in the absence of the whole context of the negotiation that occurred in confidence. As a means of highlighting the difficulty this type of commentary creates, it is not possible for TGI to address in this letter Staff's statements about the information on NGV provided by TGI with reference to any additional information provided in the course of the confidential discussions.

To the extent that Staff has decided to make its views known on the present Agreement, TGI appreciates Staff having done so in a transparent manner; the alternative of having these views being conveyed in a non-transparent manner without any ability to respond would have been unpalatable. TGI nevertheless respectfully submits that the overall Settlement Agreement package should be assessed without isolating for consideration three issues where Staff might potentially have preferred a different outcome.

With that comment, Terasen Gas would like to express sincere thanks to Commission Staff and Intervenor representatives for their active participation in achieving this Negotiated Settlement Agreement on the Application. Terasen Gas also wishes to thank the NSP facilitator, Mr. Paul Cassidy, for his leadership, guidance and assistance to all parties throughout the NSP process.

If there are any questions regarding the attached, please contact the undersigned.

Yours very truly,

TERASEN GAS INC.

Tom A. Loski

cc (e-mail only): Parties to the NSP

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-140-09

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

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

and

An Application by Terasen Gas (Vancouver Island) Inc.
for Approval of 2010 and 2011 Revenue Requirements, Rates, Cost of Service, Rate Design and
Revenue Deficiency Deferral Account Balance as at December 31, 2008

BEFORE:

A.W.K. Anderson, Panel Chair/Commissioner
D.A. Cote, Commissioner
M.R. Harle, Commissioner

November 26, 2009

O R D E R

WHEREAS:

A. On June 29, 2009, Terasen Gas (Vancouver Island) Inc. ("TGVI") filed an application for approval of interim and permanent delivery rates effective January 1, 2010 (the "Application") pursuant to sections 59 to 61 and 89 of the *Utilities Commission Act* (the "Act") and section 2.1 of the Special Direction to the British Columbia Utilities Commission ("Commission") issued pursuant to Order in Council 1510 ("Special Direction"), requesting (a) no change in 2009 sales service rates and (b) a reduction in rates for firm transportation service, other than for those customers who have specified rates in their transportation service agreements, in the amount of 4.75 percent; and

B. TGVI proposed that the rates established for 2010 should also remain in place for 2011; and

C. TGVI also applied pursuant to sections 59 to 61 of the Act and section 2.10(a)(i) of the Special Direction for interim and permanent approval of TGVI's forecast cost of service for 2010 and 2011, subject to the need to recover any Accumulated Revenue Deficiency in the Revenue Deficiency Deferral Account after December 31, 2009 and any changes in TGVI's return on equity; and

D. TGVI also applied pursuant to section 2.10(f) of the Special Direction for approval of the December 31, 2008 year-end balance in the Revenue Deficiency Deferral Account in the amount of $7,149,210, and for approval of other items identified in the Special Direction; and

E. TGVI sought other approvals in the Application, including orders pursuant to sections 59 to 61 of the Act, approving Tariff changes effective January 1, 2010 for Compression and Refueling and Transportation Services for Natural Gas Vehicles, and economic models for evaluating biogas projects and alternative energy extensions for geo-exchange, solar thermal and district energy systems to complement its core natural gas business; and

F. TGVI proposed a written hearing process to address the Application but was open to a negotiated settlement process ("NSP"); and

.../2

G. On July 2, 2009, the Commission Panel issued Order G-84-09, which provided for a Workshop on July 13, 2009 and a first Procedural Conference on July 15, 2009 to hear submissions on the appropriate regulatory process and TGVI's proposed preliminary regulatory timetable attached to that order; and

H. In accordance with Order G-84-09, TGVI held a Workshop to review the Application on Monday, July 13, 2009; and

I. Procedural Conference No. 1 was held on Wednesday, July 15, 2009 at which the Commission Panel heard submissions regarding the Application process and inclusion of Alternative Energy Solution proposals within the process; and

J. The Commission Panel considered the Submissions received at Procedural Conference No. 1, and concluded that a Regulatory Timetable establishing a second Procedural Conference following TGVI's responses to the second round of Information Requests was required. It was also determined that proposed Alternative Energy Solutions included in TGVI's Applications would be reviewed as part of the Revenue Requirements proceedings, that information requests consistent with TGI would be cross referenced to those requests, and that interim rates and the Revenue Surplus Deferral Account were not approved at that time and would be reviewed at the second procedural conference; and

K. Procedural Conference No. 2 was held on Friday, September 25, 2009 at which the Commission Panel heard further submissions regarding the process of the Application, location of the proceedings and other matters that would assist the Commission's efficient review of the Application. Primary issues raised were whether a separate Certificate of Public Convenience and Necessity ("CPCN") review was required for the Alternative Energy Solutions proposed in the Application and whether the regulatory process should be in the form of an oral or written hearing or NSP; and

L. Intervenors did not request a separate CPCN process for the Alternative Energy Solutions and all Intervenors supported an NSP for the review of the Application. The Interveners submitted that in the event the NSP does not successfully resolve all issues, an Oral Public Hearing should be subsequently ordered by the Commission Panel. TGVI requested that if an Oral Public Hearing is established that it be limited in scope; and

M. TGVI proposed a delay in its application for interim rate approval until the end of November. If a Commission decision has been issued on the Terasen Gas allowed return on equity and capital structure and this Application (the "Applications") by the end of November, then it will apply for approval of permanent rates effective January 1, 2010. If a Commission decision has not been issued on the Applications by the end of November, then TGVI will apply for interim rates effective January 1, 2010; and

N. By Order G-120-09 the Commission Panel established a negotiated settlement process for the review of the Application commencing on October 29, 2009; and

O. On November 13, 2009, the Negotiated Settlement Agreement ("NSA"), together with the Letters of Support received from the participants in the NSP ("Settlement Package"), was made public and circulated to the Commission Panel; and

P. The Settlement Package was also distributed to Registered Intervenors who did not participate in the NSP ("Other Intervenors"). The Other Intervenors were requested to provide their comments on the Settlement Package to the Commission by November 20, 2009. The Commission Panel received no comments from Other Intervenors regarding the Settlement Package; and

Q. The Commission Panel, having reviewed the proposed NSA and the comments related thereto and noting the support of all parties to the Proposed Settlement, in which only sections 7.1 (a) and (b) are severable, subject to the provisions of section 7.2, considers that approval is warranted.

NOW THEREFORE pursuant to sections 59 to 61 and 89 of the Act and the Special Direction issued pursuant to Order in Council 1510 the Commission orders as follows:

1. The Negotiated Settlement Agreement attached as Appendix A to this Order is approved.

2. TGVI is to file an amended Summary of Rates and Bill Comparison schedules based on the Negotiated Settlement Agreement.

3. The Commission will accept, subject to timely filing by TGVI, amended permanent Gas Tariff Rate Schedules in accordance with the terms of this Order. TGVI is to provide notice of the permanent rates to customers via a bill message, to be reviewed in advance by Commission Staff to confirm compliance with this Order.

DATED at the City of Vancouver, In the Province of British Columbia, this 26th day of November 2009.

BY ORDER

Original signed by:

A.W.K. Anderson
Panel Chair/Commissioner

Attachment

ERICA HAMILTON
COMMISSION SECRETARY
Commission. Secretary@bcuc.com
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Log No. 29924

VIA EMAIL

November 13, 2009

Registered Intervenors
(*TGVI-2010-11RR-RI*)

Dear Registered Intervenors:

Re: Terasen Gas (Vancouver Island) Inc.
2010-2011 Revenue Requirements and Rate Design Application
Negotiated Settlement

Enclosed with this letter is the proposed settlement package for Terasen Gas (Vancouver Island) Inc.'s 2010-2011 Revenue Requirements and Rate Design Application.

This settlement package is now public and is being submitted to the Commission and all Intervenors. Also enclosed are Letters of Comment received to date from the participants in the negotiated settlement process.

Prior to consideration by the Commission, Intervenors who did not participate in the settlement negotiations are requested to provide to the Commission with their comments on the settlement package by Friday, November 20, 2009. Thereafter, the Commission will consider the settlement package. A public hearing may not be required unless there is significant opposition to the proposed settlement.

Yours truly,

for: N. Lapierre

Erica M. Hamilton

PWN/yl
Attachments
cc: Mr. Tom Loski
Chief Regulatory Officer
Terasen Gas Inc.
(Via Email: *regulatory.affairs@terasengas.com*)

Terasen Gas

Tom A. Loski
Chief Regulatory Officer

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 592-7464
Cell: (604) 250-2722
Fax: (604) 576-7074
Email: tom.loski@terasengas.com
www.terasengas.com

Regulatory Affairs Correspondence
Email: regulatory.affairs@terasengas.com

November 13, 2009

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

Attention: Mr. Philip Nakoneshny, Director, Rates and Finance

Dear Mr. Nakoneshny:

Re: Terasen Gas (Vancouver Island) Inc. ("TGVI")
2010 and 2011 Revenue Requirements and Rate Design Application
Negotiated Settlement Agreement

On June 29, 2009, TGVI filed its 2010 and 2011 Revenue Requirements Application, Rates, Cost of Service, Rate Design and Revenue Deficiency Deferral Account Balance as at December 31, 2008 which was amended by filings on July 23 and September 22, 2009 (the "Application").

In accordance with Commission Order No. G-84-09 issued on July 2, 2009, a Workshop was held on July 13, 2009 for a review of the Application, a Procedural Conference was held on July 15, 2009, and TGVI responded to two rounds of Information Requests. In accordance with Commission Order No. G-90-09 issued on July 20, 2009, a second Procedural Conference was held on September 25, 2009 and on October 2, 2009, the Commission issued Order G-120-09 establishing a Negotiated Settlement Process ("NSP") for the Application. In accordance with Order No. G-120-09, the NSP commenced on Tuesday, November 3, 2009 and concluded on Thursday, November 5, 2009.

TGVI has reviewed the attached settlement documents, including the Negotiated Settlement Agreement and associated financial schedules (collectively the "Negotiated Settlement") arising from the NSP. TGVI recognizes the Negotiated Settlement as being the product of good faith compromises among parties with diverse interests of the issues raised by the Application. In fulfilling their role pursuant to the Commissions NSP Guidelines, Commission Staff made additional information available to the parties which they believed was in the public interest. The parties considered all such information in reaching the compromise Settlement Agreement and Terasen Gas considers the resulting Negotiated Settlement to be fair, just and reasonable. As the Negotiated Settlement represents compromises among the parties and an overall balance of interests, TGVI stresses that the Negotiated Settlement

Terasen Gas

should be considered as a package, with no part being severed unless otherwise stated in the Agreement. On that basis, TGVI accepts the Negotiated Settlement.

TGVI would like to express sincere thanks to Commission Staff and Intervenor representatives for their active participation in achieving this Negotiated Settlement Agreement on the Application. TGVI also wishes to thank the NSP facilitator, Mr. Paul Cassidy, for his leadership, guidance and assistance to all parties throughout the NSP process.

If there are any questions regarding the attached, please contact the undersigned.

Yours very truly,

TERASEN GAS (VANCOUVER ISLAND) INC.

Tom A. Loski

Attachment

cc (e-mail only): Parties to the NSP

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

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

and

An Application by Terasen Gas (Vancouver Island) Inc.
for Approval of 2010 and 2011 Revenue Requirements, Rates, Cost of Service, Rate Design and Revenue Deficiency Deferral Account Balance as at December 31, 2008
Negotiated Settlement Process

WHEREAS:

A. On June 29, 2009, Terasen Gas (Vancouver Island) Inc. ("TGVI") filed its 2010 and 2011 Revenue Requirements Application, Rates, Cost of Service, Rate Design and Revenue Deficiency Deferral Account Balance as at December 31, 2008 which was amended by filings on July 23 and September 22, 2009 (the "Application"); and

B. Amongst other things, the Application sought:

1. An order pursuant to sections 59 to 61 of the *Utilities Commission Act* (the "Act"), section 2.1 of the Vancouver Island Natural Gas Pipeline Special Direction ("Special Direction"), approving permanent rates for Core Market customers, effective January 1, 2010. As set out in Part III, Section B, Tab 3 of the Application, compared to 2009 rates, the service rates for which TGVI seeks approval are the same as 2009 sales service rates; and

2. An order pursuant to sections 59 to 61 of the Act and section 2.1 of the Special Direction, approving permanent rates for transportation customers, other than those transportation customers who have specified rates in their transportation service agreements. As set out in Part III, Section B, Tab 3 of the Application, the rates for which TGVI seeks approval are:

   a. A reduction in rates for firm transportation service in the amount of 5.18% (as compared to 2009), effective January 1, 2010; and

   b. A reduction in rates for summer interruptible transportation service in the amount of 5.18% (as compared to 2009), effective January 1, 2010; and

   c. Winter interruptible rates of $1.384/GJ effective January 1, 2010 and of $1.401/GJ effective January 1, 2011; and

3. These rates are subject to (a) the need to recover any Accumulated Revenue Deficiency in the RDDA after December 31, 2009 as explained in Part III, Section B, Tab 2 and (b) changes in TGVI's allowed return on equity as described in Part III, Section C, Tab 10; and

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

4. An order pursuant to section 2.10(a)(i) of the Special Direction approving TGVI's forecast Cost of Service for 2010 and 2011, as set out in Part III, Section C, Tab 2 of the Application, but subject to (a) the need to recover any Accumulated Revenue Deficiency in the RDDA after December 31, 2009 as explained in Part III, Section B, Tab 2 and (b) changes in TGVI's allowed return on equity as described in Part III, Section C, Tab 10; and

5. An order pursuant to sections 59 to 61 of the Act approving the schedule of demand and commodity charges as set out in Schedule A of Tariff Supplement No. 4 (Storage and Delivery Agreement between TGI and TGVI), as set out in Part III, Section B, Tab 3 of the Application.

6. An order pursuant to sections 59 to 61 of the Act approving the creation of the Rate Stabilization Deferral Account ("RSDA"), effective January 1, 2010, for the purposes of capturing any annual revenue surplus in 2010 and 2011, with any balance at the end of 2011 to be returned to Core Market customers beginning January 1, 2012 in the manner described in Part III, Section D, Tab 1.

7. An order pursuant to sections 59 to 61 of the Act approving the creation of the 2009 Revenue Surplus Account for the purposes of capturing any 2009 revenue surplus in excess of the amount needed to eliminate the debit balance in the RDDA, and its proposed allocation to customers and amortization as set out in Part III, Section D, Tab 1 of the Application.

8. An order pursuant to section 2.10(a)(i) of the Special Direction approving its forecast capital expenditures for 2010 and 2011, as set out in Part III, Section C, Tab 9 of the Application.

9. An order pursuant to section 2.10(a)(ii) of the Special Direction approving its forecast Revenue for 2010 and 2011, based on its proposed rates, as set out in Part III, Section D, Tab 1 of the Application.

10. An order approving the forecast gross O&M expenditures for the forecast period 2010 and 2011, as determined through and supported by Part III, Section C, Tab 6 of the Application of $32,104,700 and $33,650,000 respectively, and to fix those amounts for the purposes of determination of RDDA and/or RSDA balances at the end of each year.

11. An order pursuant to section 2.10 (f) of the Special Direction approving the December 31, 2008 year end balance in the RDDA of $7,149,210, as set out in Part III, Section B, Tab 2 of the Application.

12. An order pursuant to section 44.2 of the Act approving an expenditure schedule for the continuation in 2011 of TGVI's residential and commercial Energy Efficiency and Conservation ("EEC") funding, as well as new EEC funding for 2010 and 2011 for innovative technologies; and

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

13. New tariff offerings and economic tests for Compression and Refuelling and Transportation Services for Natural Gas Vehicles ("NGV"), geo-exchange, solar thermal and district energy systems and a pilot program for Biogas; and

C. A complete listing of the relief sought by TGVI in the Application was included in Section E (pages 436-443)[1] of the Application; and

D. In accordance with Commission Order No. G-84-09 issued on July 2, 2009, a Workshop was held on July 13, 2009 for a review of the Application, a procedural conference was held on July 15, 2009, and TGVI responded to two rounds of Information Requests; and

E. In accordance with Commission Order No. G-90-09 issued on July 20, 2009, a second procedural conference was held on September 25, 2009; and

F. On October 2, 2009, the Commission issued Order G-120-09 establishing a Negotiated Settlement Process ("NSP") for the Application; and

G. The Parties to the NSP were TGVI, British Columbia Old Age Pensioners et al. ("BCOAPO"), Commercial Energy Consumers Association of British Columbia ("CEC") and British Columbia Hydro and Power Authority ("BC Hydro") (collectively referred to in this Agreement as the "Parties"); and

H. At the outset of the NSP on November 3, 2009, Commission Staff provided the Parties with a document prepared by the Commission Panel titled "Issues of Particular Concern to the Commission Panel", a copy of which is appended as Appendix 1 to this Agreement; and

I. The NSP was held on November 3-5, 2009; and

J. The Parties have negotiated in good faith to achieve a compromise settlement, reflected in this Agreement, of the issues raised by the Application, and further consider the Agreement reached to be fair, just and reasonable; and

K. This Agreement consists of four sections:

Part I includes general provisions;

Part II includes the items agreed to that differ from what was requested in the Application;

Part III includes the items agreed to that remain as proposed by TGVI in the Application; and

Part IV includes revised financial schedules reflecting all items set out in the Agreement.

---

[1] Pages 436 and 437 of the Application were amended on July 23, 2009 and pages 438 to 443 were amended on September 22, 2009.

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

NOW THEREFORE THE PARTIES AGREE AS FOLLOWS

PART I – GENERAL

1. Agreement a Product of Compromise

The Parties recognize and emphasize that this Agreement is the product of compromise on the part of all Parties, yielding an overall package that the Parties consider to be fair, just and reasonable. The Parties agree that any compromises resulting from this Agreement are without prejudice to the Parties' ability to take different positions after 2011 and without prejudice to the Parties right to intervene in any applications contemplated in or resulting from this Agreement.

2. Whole Agreement

The Parties agree that, unless otherwise stated in this Agreement, portions of this Agreement cannot be removed or changed by the Commission without nullifying the whole Agreement.

3. TGVI to Manage Business

The Parties agree that TGVI will have the discretion to manage its business and determine how best to allocate the overall O&M and Capital expenditures stipulated in this Agreement.

4. Final IFRS Rate-regulated Activity Standard

The Parties acknowledge that this Agreement is predicated on the Final IFRS Rate-regulated Activity Standard permitting the financial accounting treatment contemplated in this Agreement in the manner outlined in the current Exposure Draft on Rate-regulated Activities. The Parties agree that if, in TGVI's opinion, the Final IFRS Rate-regulated Activity Standard differs from the current Exposure Draft on Rate-regulated Activities so as not to permit the financial accounting treatment contemplated in this Negotiated Settlement Agreement, which among other things anticipates the recognition of regulatory assets and liabilities for external reporting purposes, then TGVI is at liberty to apply to the Commission during the period of this Agreement for a determination of that issue, and to seek changes in the regulatory treatment contemplated in this Agreement to accord with the Final IFRS Rate-regulated Activity Standard, with the resulting impacts flowed through into rates commencing in 2011.

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

PART II – AGREED CHANGES FROM THE APPLICATION

5. Use Per Customer Rates

The Parties agree that the use per customer rates will be as set out in the Application.

6. Energy Efficiency and Conservation ("EEC") Funding for 2010

The Parties agree as follows in respect of the EEC funding sought by TGVI for 2010:

(a) TGVI will reallocate from residential and commercial EEC programs an additional $0.4 million from the amount approved for 2010 in the EEC Decision[2] to low income and rental housing programs. This brings the total for low income and rental housing programs to $0.6 million for 2010 (currently at $0.2 million).

(b) EEC funding for innovative technologies will be $0.478 million for 2010, which is the amount requested by TGVI in the Application.

(c) All agreed to EEC expenditures will be considered and evaluated within the existing portfolio, and be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 438, Item 15). However, Innovative Technology programs will be managed by TGVI as a separate segment of the overall portfolio to have a weighted average Total Resource Cost ("TRC") of 1.0 or more. TGVI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.

7. EEC Funding for 2011

7.1 The Parties agree as follows in respect of the EEC funding sought by TGVI for 2011:

(a) EEC funding for residential and commercial programs for 2011 will be $4.726 million, which is the amount requested by TGVI in the Application.

(b) TGVI will reallocate from 2011 residential and commercial EEC funding ($4.726 million for 2011) an additional $0.4 million to low income and rental housing programs. This brings the total for low income and rental housing programs to $0.6 million for 2011.

(c) EEC funding for innovative technologies will be $0.956 million for 2011, which is the amount requested by TGVI in the Application.

---

[2] Decision and Order No. G-36-09 dated April 16, 2009 in the TGI-TGVI Energy Efficiency and Conservation Application.

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

(d) All agreed to EEC expenditures will be considered and evaluated within the existing portfolio, and be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 438, Item 15). However, Innovative Technology programs will be managed by TGVI as a separate segment of the overall portfolio to have a weighted average TRC of 1.0 or more. TGVI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.

(e) TGVI will report to the Commission on innovative technology programs as part of TGVI's annual report on EEC activities required under the EEC Decision.

The Parties offer the following rationale for the agreed upon 2011 EEC funding.

All Parties agree that it is important to maintain EEC funding levels in 2011 to allow customers to have continued access to EEC programs and incentives. The residential and commercial EEC programs relating to the $4.726 million funding in 2011 on a portfolio basis in aggregate have a TRC of one or more. This means that, from a resource perspective and on a portfolio basis, these programs are expected to yield favourable results for customers. The predictability and continuity of these programs on a sustained basis is critical to their overall success.

Issue No. 1 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "EEC Program – TGVI is to provide results of programs approved by the EEC Decision and expectations for new programs before the Commission Panel will approve additional EEC program funding."

There are practical difficulties associated with the approach identified by the Commission Panel. They include the following:

- As per the EEC Decision (Order No. G-36-09), TGVI will be reporting 2009 activities and results by no later than March 31, 2010. This report will also outline the forecasted activities and programs for 2010. Recognizing the timing of the recent EEC Decision and its current implementation in the Fall of 2009, the EEC Report for 2009 results will give the Commission and stakeholders another check point to validate the level of spend for 2011. However, there is expected to be very little additional information on the results of programs available in March 2010 than exists presently and is included in the evidentiary record of this proceeding. TGVI's EEC programs only completed start up phase in the Fall of 2009. It typically takes longer than 6-8 months to achieve momentum with EEC programs. There will be no information available in March 2010 on results for programs relating to innovative technologies initiated in 2010 as a result of this Agreement. The information that the Commission Panel appears to desire will be more likely included in TGVI's 2010 results report to be filed in March 2011.

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

- Employees responsible for the programs at TGVI, whose salaries are funded from EEC funding, will face the prospect of losing their jobs in 2011. This could lead to employee retention issues. Employee turnover issues may disrupt the program implementation progress and potentially be more costly if EEC activity is ceased and later resumed.

- Programs will need to begin winding down in advance of 2011 if the 2011 funding is not approved. For example, programs will need to have an end date of December 31, 2010 which may not yield positive results since programs will be winding up in the middle of the heating season.

7.2 The Parties agree that the Commission may sever Section 7.1 (a) and (b) above from this Agreement, with the remainder of this Agreement remaining in force and effect. If the Commission severs Section 7.1 (a) and (b), then the Parties agree that the following provisions take effect:

(a) The Residential and Commercial EEC programs totaling $4.726 million in 2011 will be removed from the EEC expenditure forecast and the revenue requirements for 2011. (If 7.2 takes effect, the financial schedules in Part IV of this Agreement and the cost of service/revenue requirements resulting from this Agreement will be revised to reflect this).

(b) The Parties agree that the first annual report on EEC Activities, which was due to be filed on March 31, 2010 pursuant to Order No. G-36-09, will instead be filed on or before June 30, 2010. Concurrent with that report, TGVI will file an application with the anticipation of a decision within 120 days after filing. The application will include requests for:

i. approval of the above EEC funding for 2011;

ii. approval of the same financial treatment approved in the EEC Decision; and

iii. approval for the continuation of the portfolio approach and assessment methodology as approved in the EEC Decision.

8. Alternative Energy Solutions

Alternative Energy Solutions ("AES") means Geo-exchange, Solar-thermal and District Energy Systems as those terms are described in the Application.

The forecast costs of pursuing AES projects in the TGVI service area were included in the Shared Services cost pool, which is allocated pursuant to the Shared Services Agreement among TGI, TGVI and TGW. The costs related to AES projects that would otherwise have been allocated to TGVI have been allocated to TGI's New Energy Solutions Deferral Account pursuant to the Settlement Agreement for the TGI 2010 and 2011 Revenue Requirements. Accordingly, TGVI withdraws its requests for relief in the Application relating to AES. The Parties acknowledge that TGI will be pursuing AES projects within the TGVI

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

service area and agree that the costs incurred by TGI to provide AES will not be recovered in TGVI's natural gas service rates. Any direct costs, sales and marketing O&M and other development costs incurred by TGVI in assisting TGI in pursuit of AES will be directly charged to the TGI New Energy Solutions Deferral Account of TGI by timesheets or other direct charge.

9. Natural Gas for Vehicles ("NGV")

The Commission Issue No. 2 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "Natural Gas Vehicles ("NGV") – if NGV is to proceed why should the natural gas ratepayer fund this initiative rather than Terasen's non-regulated businesses or the competitive market?"

The Parties agree:

(a) The new NGV Service Rate Schedule (as set out in the Application Appendix J-4) – the NGV Service Rate Schedule should be approved as filed; and

(b) NGV Grants will be accounted for on a net-of-tax basis in a deferral account and amortized over a five year term (the same treatment as under TGI Rate Schedule 6 (as set out in the Application, Part III, Section C, Tab 3, page 224); and

(c) The marketing costs in support of NGV that are included in the Application are appropriately included in the 2010 and 2011 cost of service.

(d) Upon acceptance of this Agreement by the Commission, TGVI withdraws its request in the Application for the following:

i. Compression and Refueling Service Rate Schedule; and

ii. the Compression Service ("CS") Test; and

iii. NGV non-rate base deferral account for Compression Equipment Costs and Expenses.

The Parties acknowledge that these requests are being withdrawn by TGVI to facilitate a settlement on other issues presented in the Application. The Parties agree that TGVI's withdrawal of its requests regarding NGV is without prejudice to TGVI's right to bring forward similar requests in 2010 or 2011 or otherwise in the future. The Parties acknowledge that TGVI intends to develop this area of business and that TGVI anticipates it will bring forward applications on NGV projects to the Commission on a case-by-case basis during the term of this Agreement and in future years. The Parties agree that TGVI is at liberty to do so.

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

10. Biogas

Issue No. 3 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

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

The Parties agree that, upon acceptance of this Agreement by the Commission, TGVI withdraws its requests in this Application related to Biogas. The Parties acknowledge that these requests are being withdrawn to facilitate a settlement on other issues presented in this Application. The Parties agree that TGVI will bring forward an application (the "Biogas Application") during the test period that will:

(a) Address the economic assessment model; and

(b) Provide Biogas rates (including green rate, transportation rate, etc.); and

(c) Provide for recovery of costs associated with providing Biogas service.

TGVI may include in the Biogas Application any Biogas Projects under development at that time. TGVI is, however, not precluded from applying for Commission approval in respect of individual Biogas Projects at any time, either prior to the Biogas Application or afterwards.

11. CPCN Threshold

Issue No. 6 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "CPCN threshold – why should the threshold increase from $5 million."

The Parties accordingly agree that the CPCN threshold will be $5 million for 2010 and 2011. TGVI's Category C Capital Expenditures forecast for the forecast period will be revised to reflect this change (please see item 13 below).

12. Category A Capital

TGVI had utilized an incorrect inflation rate in the Application when calculating the forecast capital expenditures for Distribution Mains (BCUC IR 1.120.5). The Parties agree to use the correct inflation rate, resulting in a decrease to the Category A Capital Expenditures of $188 thousand in 2010 and $154 thousand in 2011, and an associated decrease in the Revenue Requirement in each of those years, from the amounts set out in the Application.

13. Category C Capital

As a consequence of the CPCN threshold being established at $5 million for 2010 and 2011 (see item 11 above), TGVI will file a CPCN application for the Victoria Regional Office project identified in TGVI's Application. The Category C Capital will consequently be reduced by $5.2 million in 2010 and a further $3.3 million (totaling $8.5 million) in 2011. TGVI will seek deferral treatment for 2011 of the capital costs associated with those projects at the time of filing the CPCN Applications.

The Parties agree that Category C Capital will additionally be reduced by a total of $0.5 million in each of 2010 and 2011. The revised Category C Capital Expenditures, reflecting the removal of the Victoria Regional Office capital expenditures and the $0.5 million IT Capital reduction, are now $4.4 million in 2010 and $4.1 million in 2011.

14. Gross O&M (to be recovered from gas customers)

The Parties agree that the proposed gross O&M recoverable from gas customers is reduced by $0.874 million in 2010 and $0.947 million in 2011, resulting in gross O&M in 2010 of $31.231 million and gross O&M of 2011 of $ 32.702 million. The Parties agree to fix the Gross O&M amounts for the purposes of determination of RDDA and/or RSDA balances at the end of each year. The changes as compared to the Application include the following three components:

1. Reduced Shared Services costs from TGI in the amount of $0.339 million in 2010 and $0.491 million in 2011 as discussed in Item 15 below; and

2. Reduced Corporate Services cost from Terasen Inc. in the amount of $0.535 million in 2010 and $0.540 million in 2011, as discussed in Item 15 below.

3. TGVI inadvertently omitted to include the fixed costs associated with electric Demand charges for general operations of the LNG facility including liquefaction, vapourization, and boil-off compression. The Parties agree that these incremental costs, totalling $83 thousand ($37 thousand for additional electricity and $46 thousand for additional fuel), will be included in the 2011 gross O&M amounts (BCUC IR 1.101.9).

15. Shared Services/Corporate Services

The Parties agree that the amount of Shared Services costs allocated to TGVI from TGI should be reduced by $0.339 million in 2010 and $0.491 million in 2011 as a result of the outcome of the concurrent TGI RRA.

The Parties agree that the amount of Corporate Services costs allocated to TGVI from Terasen Inc. should be reduced by $0.535 million in 2010 and $0.540 million in 2011. As a result of these Corporate Services reductions, and as contemplated in the TGI 2010-2011 RRA Settlement Agreement, the amount of Corporate Services allocated to TGI from Terasen Inc. will increase by a corresponding amount in each year to ensure recovery of all of the combined Corporate Services.

The Parties agree that the current Shared Services Agreement between TGVI and TGW will be discontinued, and acknowledge that TGI will be providing shared services to TGW.

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

16. Depreciation Study

The Parties agree that the depreciation rates specified in the Gannett Fleming study included the Application under Appendix H-2 for Parts I-III, and in the Supplemental filing dated July 8, 2009 for Parts IV and V, will be implemented effective January 1, 2010, with the exception of:

(a) incorporating the correct updated rates from the depreciation study results in a change in the rate for asset class 475 from 1.62 per cent to 1.94 per cent, and a change in the rate for asset class 477 from 4.92 per cent to 4.60 per cent (BCUC IR 1.146.3); and

(b) the component of those rates that represent recovery of negative salvage (see item 17 below).

Adjusting for the Distribution Asset Classes, negative salvage, and overheads capitalized and capital expenditures changes yields total depreciation expense of $21.8 million in 2010 and $26.0 million in 2011, of which approximately $1.2 million results from the updated Gannett Fleming depreciation study.

The Parties agree that TGVI will undertake an updated depreciation study to be included as part of TGVI's next Revenue Requirements Application. This study will address the methodology and rates for net negative salvage to be included in cost of service for future periods. TGVI will work with Commission staff and a depreciation rate specialist in determining the requirements of the study.

17. Negative Salvage Values

On an annual basis, TGVI includes a provision for estimated net negative salvage value (removal costs less proceeds) in its depreciation rates. This treatment, which was approved as recently as 2004, along with an estimate of the salvage amount to be included in depreciation rates recognizes that net negative salvage value is a cost of providing service using the asset and should be recovered from customers over the useful life of the asset. An alternative treatment is to recover the net negative salvage values at the time they are incurred resulting in future customers paying for the removal costs, which TGVI views as inappropriate. The inclusion of a provision for estimated net negative salvage value in depreciation rates is a practice that has been followed by TGVI historically, and with this RRA TGVI had proposed continuation of this treatment. This treatment is consistent with the BCUC Uniform System of Accounts and is generally followed by other investor-owned utilities in British Columbia and across Canada.

The Parties agree that for the purposes of the two year period covered by this Agreement, the provision for net negative salvage (net removal costs) will be removed from the depreciation estimates. Instead, an estimate of the amount of net removal costs to be incurred in each of the years 2010 and 2011 ($0.343 million and $0.344 million) will be included in the cost of service and recovered from customers in each of those years. Any variances between the actual amount of net removal costs realized and the estimated amounts included in cost of service will be recorded in a new deferral account created for this purpose that will be called the "Removal Cost Deferral Account". The amount

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

accumulated in the Removal Cost Deferral Account over the two year period of this Agreement will be recovered from (or returned to) customers in 2012.

TGVI continues to be of the position that removal costs should be recovered over the service life of the asset and not at the time the removal costs are actually incurred. TGVI will work with Commission staff and a depreciation rate specialist in determining both the methodology and estimates for the removal costs and include the documentation to support the rates in its next depreciation study filed as part of its next Revenue Requirement Application.

The Parties agree that TGVI will update its financial schedules to increase the opening balance of the Accumulated Amortization of Contributions in Aid of Construction and correspondingly decrease the opening balance of Accumulated Depreciation by $13.275 million (BCUC IR 2.37.1.1) with no effect on rate base or cost of service.

18. Unrecovered Losses

Issue No. 7 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "Unrealized losses in rate base – should some of these losses be to the shareholder? Parties should present a separate settlement package."

Unrealized (unrecovered) losses relate to Unrecovered Depreciation on assets used 100 per cent for the provision of utility service to ratepayers (BCUC IR 1.112.1).

The Parties agree that the treatment for unrecovered losses as proposed in the Application is acceptable for the 2010 and 2011 period covered by this Agreement. TGVI will work with Commission staff and a depreciation rate specialist in determining both the methodology and estimates for the unrecovered losses and include the documentation to support the rates in its next depreciation study filed as part of its next Revenue Requirement Application.

19. Overheads Capitalized

The Parties agree to a change in the overheads capitalized rate to 14 per cent of Gross O&M for 2010 and 2011.

20. International Financial Reporting Standards ("IFRS") 2010 Impact

Issue No. 4 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "International Financial Reporting Standards ("IFRS") – could have no IFRS impact in 2010."

The Parties agree to defer the 2010 revenue requirement impact of IFRS, resulting from Items 25 (b), (c), (d) and (e) in this Agreement, to be reflected in revenue requirements in 2011 up to a maximum of $2.0 million. Amounts, if any, over $2.0 million would be deferred and reflected in revenue requirements after 2011 based on the amortization approved by the Commission at that time.

21. Allocation of 2009 Revenue Surplus Account ("RSA") Balance (Application page 322 Item (7)(b))

The Commission approved the creation of a 2009 Revenue Surplus Account in Order No. G-84-09. TGVI currently forecasts that the RDDA balance will reach zero in 2009 and that a surplus will be recorded in the 2009 RSA. The actual balance in the 2009 RSA will not be known until the Commission approves the 2009 year end balance in the RDDA, pursuant to section 2.10(f) of the Special Direction.

Issue No. 8 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "Rate Design – should BC Hydro receive any refund for the expected 2009 RDDA surplus?"

The Parties have considered the issue raised by the Commission Panel. The Parties agree, for the purposes of achieving overall Agreement, that the answer to Commission Panel Issue No. 8 is, "Yes", and that the forecast balance in the 2009 RSA of $2.962 million will be amortized equally over the forecast years 2010 and 2011 to all customers, other than the VIGJV and TGI Squamish Service Area (TGI Squamish), as follows:

(a) $2.677 million to Core Market

(b) $0.246 million to BC Hydro

(c) $0.039 million to TGW

Any variance between the forecast and actual 2009 RSA balance will be captured in the RSDA described below.

22. Rate Stabilization Deferral Account ("RSDA") (Application page 323 Item (7)(c))

Variances between forecast cost of service and actual cost of service, other than O&M, are items that will be "trued up to actual" as per the Special Direction. Gross O&M will be as stated in Item 14, and not "trued up to actual" (i.e. variances from forecast O&M specified in Item 14 will be an at-risk item for the shareholder). The allowed rate of return on Equity will be adjusted to that approved by the Commission during the period of the settlement and will not be trued up to actual. For clarity, this means that approved rate of return on equity percentage will apply to the actual rate base consistent with the methodology employed since 2003 for TGVI.

The Parties agree that TGVI will establish a RSDA to capture:

(a) differences in 2010 and 2011 between:

i. the net revenues received; and

ii. the actual, "trued-up", cost of service, excluding O&M variances from forecast stated in Item 14; and

(b) any Accumulated Revenue Deficiency in the RDDA after December 31, 2009.

The Parties agree that any balance in the RSDA will be amortized into the cost of service after 2011. However, the Parties agree that the following issues will be deferred to a future proceeding:

(a) how any balance in the RSDA will be allocated among customer classes; and

(b) the period over which any balance in the RSDA will be amortized into the cost of service.

RATE DESIGN

23. Rate Design

The Vancouver Island Natural Gas Pipeline Agreement contemplates the Provincial Government Royalty Revenues to TGVI ceasing at the end of 2011. The Parties agree that given the pending loss of Royalty Revenues from the Provincial Government and the strategies to deal with the potential rate shock associated with that circumstance, including potential amalgamation, that it would be appropriate to defer a full scale rate design at this time.

The Parties have differing views on the appropriate rate design. The Parties did not agree on an appropriate rate design, and did not agree on:

(a) Various cost allocation principles;

(b) Revenue to cost ratios; and

(c) The treatment of interruptible transportation revenues.

Instead, the Parties agree that this Negotiated Settlement Agreement is without prejudice to any position Parties may take in the future. The Parties agree that no precedent is set by this Agreement.

24. Rate Proposals

The Parties agree that the proposed core market rate freeze for the two year test period is accepted. The Parties agree to the rates for each customer class is set out in Schedule 1 under Part IV of this Agreement.

Issue No. 5 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "2010 Rate Changes – in the event that a 2010 rate reduction were to occur as a result of negotiations, the current rates should remain unchanged and place the revenue surplus into a deferral account to apply against 2011 and future rate increases with a phase in amortization that strives for rate stability."

The Parties agree that Commission Panel Issue No. 5 is addressed for core market customers.

The Parties agree that the rates for transportation customers, effective January 1, 2010, other than those that have specified rates set out in their contract (VIGJV and TGI Squamish), are as set out below.

(a) BC Hydro

i. Firm Transportation Rate $0.830 per GJ

ii. Summer Interruptible Rate $0.830 per GJ

iii. Winter Interruptible $1.330 per GJ

(b) TG Whistler

i. Firm Transportation Rate $0.930 per GJ

These transport rates are based on TGVI's current allowed return on equity ("ROE") of 9.17 per cent and subject to changes flowing from the Commission's decision in TGVI's concurrent ROE and Capital Structure Application[3], or as adjusted from time to time by the Commission. Nothing in this Agreement precludes TGVI from applying to the Commission in 2010 or 2011 for changes to its allowed ROE and capital structure.

The Parties agree to the following formula to reflect changes in the allowed ROE in the transportation rates, other than those that have specified rates set out in their contract (VIGJV and TGI Squamish). Every 1 basis points difference in the approved ROE as compared to the current ROE of 9.17 per cent will cause the firm and interruptible rates to change in the same direction by 0.034 cents per GJ rounded to the nearest tenth of a cent.

PART III – REQUESTS UNCHANGED FROM THE APPLICATION

The Parties agree to the following items set out in this section, which are consistent with the proposals in TGVI's Application.

---

[3] Filed jointly by the Terasen Utilities [TGI, TGVI. and Terasen Gas (Whistler) Inc.] on May 15, 2009.

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

25. Accounting Policy Changes as per Application Part III, Section E - Approvals Sought - to be effective January 1, 2010

The Parties agree to the following accounting policy changes, as set out in TGVI's Application:

(a) Training and Feasibility Study Costs to be treated as O&M expense, rather than capital (Application Page 438 and 439, Item 18).

(b) Capitalization of Major Inspection and Overhaul Costs, including the creation of new Asset Classes (Application Page 438 and 439, Item 18).

(c) Capitalization of the Current Service portion of Pensions and OPEBs expense that is applicable to capital projects (Application Page 438 and 439, Item 18).

(d) Capitalization of Depreciation on Assets used in Construction (Application Page 438 and 439, Item 18).

(e) All capital expenditures, including CPCNs, to be included in plant in service (and rate base) in the month following the available-for-use date, with depreciation starting at that time (Application Page 438 and 439, Item 18).

(f) Adoption of the effective interest method for calculating interest expense on long-term debt (Application Page 438 and 439, Item 18).

26. Various Accounting Related Proposals as per Application Part III, Section E - Approvals Sought effective January 1, 2010

The Parties agree to the following accounting related changes, as set out in TGVI's Application:

(a) Adoption of the Cash Working Capital Lead/Lag Days as set out in the Lead/Lag study (Application page 438, Item 16d).

(b) The treatment of Customer Security Deposits as part of the unfunded debt, instead of as a component of working capital (Application Page 438 and 439 Item 18).

(c) The inclusion of the reserve for bad debts as a component of working capital (Application Page 438 and 439 Item 18).

(d) Consolidated Core Market Administration Expenses (for TGI, TGVI and TGW), including allocation percentages (Application page 438, Item 16e).

27. Tariff Change Proposals as per Application Part III, Section E - Approvals Sought, Item 19

The Parties agree to the following Tariff changes, as set out in TGVI's Application:

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

(a) Revised Fee New Customer Application fee from $85 to $25

(b) Revised dishonoured cheque charge from $10 to $20

(c) Revised Fee Meter Testing fee from $50 to $60

(d) Removed special meter reading charge

(e) Removed move meter from inside to outside premises at consumer's request charge

(f) Removed resetting of meter and regulator charge

(g) Removed where services performed at cost charge

(h) Changes to the Standard Terms and Conditions as set out in Part III, Section C, Tab 12 and Appendix J-2 of the Application.

28. <u>Deferral Account Proposals as per Application Part III, Section E - Approvals Sought, Item 17</u>

The Parties agree to the continuation, modification or adoption of the following deferral accounts as set out in TGVI's Application:

(a) Deferral Accounts - No Change:

i. Gas Cost Variance Account (Application page 316, Item (1)).

ii. Insurance variance (Application page 318, Item (3) (a)).

iii. Pension & OPEB variance (Application page 318, Item (3) (b)).

iv. Olympic Security costs (Application page 318, Item (3) (d)).

v. IFRS conversion costs (Application page 318, Item (3) (e)).

vi. PCEC Start Up Costs (Application page 319 Item (5)(a)).

vii. Accounts Amortized in 2010 (Application page 321, Item (6) (c)).

viii. RDDA (Application Page 322 Item (7)(a)).

(b) Deferral Accounts - New:

i. BCUC Levies variance (Application page 318, Item (3) (c)).

ii. Costs of applications (CCE, ROE, RRA) (Application page 319, Item (4)).

iii. IFRS Transitional Deferral Account (Application page 319, Item (5) (b)).

~~**CONFIDENTIAL**~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

iv. Pension and OPEB funding differences (Application page 320, Item (5) (c)).

v. Gains and Losses on Asset Disposition (Application page 320, Item (5) (d)).

29. RDDA Balance as at December 31, 2008

The Parties agree pursuant to section 2.10 (f) of the Special Direction that the December 31, 2008 year end balance in the RDDA is $7,149,210, as set out in Part III, Section B, Tab 2 of the Application. (Application page 437, Item 12)

30. Cost of Service

The Parties agree pursuant to section 2.10(a)(i) of the Special Direction that TGVI's forecast Cost of Service for 2010 and 2011 will be as set out in Schedule 14, in Part IV of this Agreement, but subject to (a) the need to recover any Accumulated Revenue Deficiency in the RDDA after December 31, 2009 as explained in Part III, Section B, Tab 2 and (b) changes in TGVI's allowed return on equity. (Application page 436, Item 4).

31. Capital

The Parties agree pursuant to section 2.10(a)(i) of the Special Direction that TGVI's forecast capital expenditures for 2010 and 2011 will be as set out in Schedule 42, in Part IV of this Agreement. (Application page 437, Item 9)

32. Revenue

The Parties agree pursuant to section 2.10(a)(i) of the Special Direction that TGVI's revenues will be as per Schedule 14, in Part IV of this Agreement.

33. Customer Segmentation

The Parties agree to accept the customer segmentation as filed in the Application.

34. Mt. Hayes LNG Storage – Storage and Delivery Agreement

The Parties agree to accept Schedule A of Tariff Supplement No. 4 (Storage and Delivery Agreement between TGI and TGVI), as set out in Part III, Section B, Tab 3 of the Application.

~~CONFIDENTIAL~~
NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

PART IV – REVISED FINANCIAL SCHEDULES

The revised Financial Schedules follow.

Rate Base

Return on Capital

RDDA

~~CONFIDENTIAL AND WITHOUT PREJUDICE - FOR NSP PURPOSES ONLY~~

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
CORE MARKET AND TRANSPORTATION RATES Schedule 1
EFFECTIVE JANUARY 1, 2010
In $/GJ

Core Market Rate Class	Approved Rate (in $/GJ) 2009		Approved Rate (in $/GJ) 2010		Approved Rate (in $/GJ) 2011	
	Basic Charge	Variable Charge	Basic Charge	Variable Charge	Basic Charge	Variable Charge
RGS	$ 10.500	$ 14.325	$ 10.500	$ 14.325	$ 10.500	$ 14.325
AGS	$ 40.000	$ 12.373	$ 40.000	$ 12.373	$ 40.000	$ 12.373
SCS-1	$ 9.450	$ 16.940	$ 9.450	$ 16.940	$ 9.450	$ 16.940
SCS-2	$ 33.530	$ 16.455	$ 33.530	$ 16.455	$ 33.530	$ 16.455
LCS-1	$ 61.000	$ 13.353	$ 61.000	$ 13.353	$ 61.000	$ 13.353
LCS-2	$ 97.820	$ 12.311	$ 97.820	$ 12.311	$ 97.820	$ 12.311
LCS-3	$ 201.510	$ 12.015	$ 201.510	$ 12.015	$ 201.510	$ 12.015
HLF	$ 250.000	$ 8.697	$ 250.000	$ 8.697	$ 250.000	$ 8.697
ILF	$ 250.000	$ 10.097	$ 250.000	$ 10.097	$ 250.000	$ 10.097

Transportation Customers	Approved Rate (in $/GJ) 2009	Approved Rate (in $/GJ) 2010	Approved Rate (in $/GJ) 2011
BC Hydro - Firm Rate	$ 0.912	$ 0.830	$ 0.830
BC Hydro - Winter IT Rate	$ 1.557	$ 1.330	$ 1.330
TGW	$ 1.026	$ 0.930	$ 0.930

Note:
1. The rates for Vancouver Island Gas Joint Venture ("VIGJV") and TGI Squamish are set as per their respective transporation service agreements.

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 2

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Approved Rates	2009 Surplus	2009 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	12,636	12,264	-	12,264	(372)	Schedule 15
3	Transportation	21,692	22,946	-	22,946	1,254	Schedule 15
		34,328	35,210	-	35,210	882	
4	UTILITY REVENUE						
5	Sales - Existing Rates	$ 184,795	$ 179,501	$ -	$ 179,501	$ (5,294)	Schedule 18
6	- Increase / (Decrease)		-	(14,443)	(14,443)	(14,443)	
7	Transportation - Existing Rates	20,126	22,194	-	22,194	2,069	Schedule 18
8	- Increase / (Decrease)			-	-	-	
9	**Total Revenue**	204,921	201,695	(14,443)	187,252	(17,668)	
10	Royalty Credit	(48,701)	(28,095)	-	(28,095)	20,606	
11	GCVA Amortization	3,045	4,162		4,162	1,117	Schedule 58
12	GCVA Additions	-	5,781	-	5,781	5,781	
13	Cost of Gas	129,512	99,314	-	99,314	(30,198)	Schedule 21
14	RACOG Including GCVA Impacts	83,856	81,162		81,162	(2,694)	
15	**Gross Margin**	121,064	120,533	(14,443)	106,090	(14,975)	
16	Operation and Maintenance (allowed)	26,178	26,178	-	26,178	(0)	
17	Transportation Expenses	4,374	3,977	-	3,977	(397)	
18	Operating Leases	828	828	-	828	-	
19	Property Taxes	8,362	8,449	-	8,449	87	Schedule 26
20	Depreciation and Amortization	$32,230	23,017	-	23,017	(9,213)	Schedule 27
21	Removal Costs (Depreciation)	-	-	-	-	-	
22	IFRS Transitional Deferral	-	-	-	-	-	
23	Other Operating Revenue	(1,062)	(893)	-	(893)	169	Schedule 22
24		70,911	61,556	-	61,556	(9,355)	
25	Utility Income Before Income Taxes	50,153	58,977	(14,443)	44,534	(5,619)	
26	Income Taxes	11,905	13,178	(4,331)	8,847	(3,058)	Schedule 30
27	**EARNED RETURN**	$ 40,115	$ 47,666	$ (10,112)	$ 37,554	$ (2,561)	
28	VINGPA Grind	(1,867)	(1,867)	-	(1,867)	-	Schedule 30
27	**EARNED RETURN After VINGPA Adjustment**	$ 38,248	$ 45,799	$ (10,112)	$ 35,687	$ (2,561)	
28	**UTILITY RATE BASE**	$ 539,525	$ 540,195	$ (407)	$ 539,788	$ 264	Schedule 8
29	**RATE OF RETURN ON UTILITY RATE BASE**						
30	Before VINGPA Adjustment	7.11%	8.82%		6.96%	-0.15%	
31	After VINGPA Adjustment	7.09%	8.48%		6.61%	-0.48%	
32	**EARNED RETURN**	$ 40,115	$ 47,666	$ (10,112)	$ 37,554	$ (2,561)	Schedule 68
33	VINGPA Adjustment	(1,867)	(1,867)	-	(1,867)	-	
34	**EARNED RETURN After VINGPA Adjustment**	$ 38,248	$ 45,799	$ (10,112)	$ 35,687	$ (2,561)	x-ref Schedule 5

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 3

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Approved Rates	2010 Surplus	2010 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	12,264	12,241	-	12,241	(23)	Schedule 16
3	Transportation	22,946	22,309	-	22,309	(637)	Schedule 16
		35,210	34,550	-	34,550	(660)	
4	UTILITY REVENUE						
5	Sales - Existing Rates	$ 179,501	$ 179,445	$ -	$ 179,445	$ (56)	Schedule 19
6	- Increase / (Decrease)	(14,443)	-	(42,605)	(42,605)	(28,162)	
7	Transportation - Existing Rates	22,194	20,669	-	20,669	(1,525)	Schedule 19
8	- Increase / (Decrease)	-		-	-	-	
9	**Total Revenue**	187,252	200,114	(42,605)	157,509	(29,743)	
10	Royalty Credit	(28,095)	(35,832)	-	(35,832)	(7,737)	
11	GCVA Amortization	4,162	(4,047)		(4,047)		Schedule 59
12	GCVA Additions	5,781	-	-	-	(5,781)	
13	Cost of Gas Sold	99,314	98,628	-	98,628	(686)	Schedule 21
14	RACOG Including GCVA Impacts	81,162	58,750		58,750	(22,413)	
15	**Gross Margin**	106,090	141,364	(42,605)	98,759	(29,057)	
16	Operation and Maintenance	26,178	26,858	-	26,858	680	Schedule 23
17	Transportation Expenses	3,977	4,015	-	4,015	38	
18	Operating Leases	828	-	-	-	(828)	
19	Property Taxes	8,449	9,119	-	9,119	670	Schedule 26
20	Depreciation and Amortization	23,017	19,202	-	19,202	(3,815)	Schedule 28
21	Removal Costs (Depreciation)	-	343	-	343	343	
22	IFRS Transitional Deferral	-	1,400	-	1,400	1,400	
23	Other Operating Revenue	(893)	(717)	-	(717)	176	Schedule 22
24		61,556	60,220	-	60,220	(1,336)	
25	Utility Income Before Income Taxes	44,534	81,144	(42,606)	38,538	(5,996)	
26	Income Taxes	8,847	13,661	(12,140)	1,521	(7,326)	Schedule 31
27	**EARNED RETURN**	$ 37,554	$ 69,350	$ (30,466)	$ 38,884	$ 1,330	
28	VINGPA Grind	(1,867)	(1,867)	-	(1,867)	-	Schedule 31
27	**EARNED RETURN After VINGPA Adjustment**	$ 35,687	$ 67,483	$ (30,466)	$ 37,017	$ 1,330	
28	**UTILITY RATE BASE**	$ 539,788	$ 554,763	$ (750)	$ 554,013	$ 14,224	Schedule 9
29	**RATE OF RETURN ON UTILITY RATE BASE**						
30	Before VINGPA Adjustment	6.96%	12.50%		7.02%	0.06%	
31	After VINGPA Adjustment	6.61%	12.16%		6.68%	0.07%	
32	**EARNED RETURN**	$ 37,554	$ 69,350	$ (30,466)	$ 38,884	$ 1,330	Schedule 69
33	VINGPA Adjustment	(1,867)	(1,867)	-	(1,867)	-	
34	**EARNED RETURN After VINGPA Adjustment**	$ 35,687	$ 67,483	$ (30,466)	$ 37,017	$ 1,330	x-ref Schedule 6

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C Tab 13 Schedule 4

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Approved Rates	2011 Surplus	2011 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	12,241	12,433	-	12,433	192	Schedule 17
3	Transportation	22,309	22,017	-	22,017	(292)	Schedule 17
		34,550	34,450	-	34,450	(100)	
4	UTILITY REVENUE						
5	Sales - Existing Rates	$ 179,445	$ 182,402	$ -	$ 182,402	$ 2,957	Schedule 20
6	- Increase / (Decrease)	(42,605)	-	(24,603)	(24,603)	18,002	
7	Transportation - Existing Rates	20,669	20,500	-	20,500	(169)	Schedule 20
8	- Increase / (Decrease)	-		-	-	-	
9	**Total Revenue**	157,509	202,902	(24,603)	178,299	20,790	
10	Royalty Credit	(35,832)	(40,091)	-	(40,091)	(4,260)	
11	GCVA Amortization	(4,047)	-	-	-		Schedule 60
12	GCVA Additions	-	-	-	-	-	
13	Cost of Gas Sold (Including Gas Loss)	98,628	107,311	-	107,311	8,683	Schedule 21
14	RACOG Including GCVA Impacts	58,750	67,220		67,220	8,470	
15	**Gross Margin**	98,759	135,682	(24,603)	111,079	12,107	
16	Operation and Maintenance	26,858	28,136	-	28,136	1,277	Schedule 23
17	Transportation Expenses	4,015	4,122	-	4,122	107	
18	Operating Leases	-	-	-	-	-	
19	Property Taxes	9,119	9,564	-	9,564	445	Schedule 26
20	Depreciation and Amortization	19,202	25,232	-	25,232	6,030	Schedule 29
21	Removal Costs (Depreciation)	343	344	-	344	1	
22	IFRS Transitional Deferral	1,400	(1,400)	-	(1,400)	(2,800)	
23	Other Operating Revenue	(717)	(9,752)	-	(9,752)	(9,035)	Schedule 22
24		60,220	56,246	-	56,246	(3,975)	
25	Utility Income Before Income Taxes	38,538	79,437	(24,604)	54,833	16,295	
26	Income Taxes	1,521	10,352	(6,518)	3,834	2,313	Schedule 32
27	**EARNED RETURN**	$ 38,884	$ 70,952	$ (18,086)	$ 52,866	$ 13,982	
28	VINGPA Grind	(1,867)	(1,867)	-	(1,867)	-	Schedule 32
27	**EARNED RETURN After VINGPA Adjustment**	$ 37,017	$ 69,085	$ (18,086)	$ 50,999	$ 13,982	
28	**UTILITY RATE BASE**	$ 554,013	$ 729,375	$ (381)	$ 728,994	$ 174,982	Schedule 10
29	**RATE OF RETURN ON UTILITY RATE BASE**						
30	Before VINGPA Adjustment	7.02%	9.73%		7.25%	0.23%	
31	After VINGPA Adjustment	6.68%	9.47%		7.00%	0.31%	
32	**EARNED RETURN**	$ 38,884	$ 70,952	$ (18,086)	$ 52,866	$ 13,982	Schedule 70
33	VINGPA Adjustment	(1,867)	(1,867)	-	(1,867)	-	
34	**EARNED RETURN After VINGPA Adjustment**	$ 37,017	$ 69,085	$ (18,086)	$ 50,999	$ 13,982	x-ref Schedule 7

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
Tab 13
Schedule 5

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

			2009				
			----Cost of Service Rates-----				
Line No.	Particulars	2009 APPROVED	Approved Rates	Required Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return After VINGPA Adjustment	$36,756	$45,799	($10,112)	$35,687	($1,069)	Schedule 2
3	Deduct - Interest on Debt	(20,325)	(17,759)	4	(17,755)	2,570	
4	Add - O&M Savings	2,127	2,435	-	2,435	308	
5	Add- Non-Tax Ded. Expense (Net)	15,609	6,015	-	6,015	(9,595)	Schedule 33
6	Accounting Income After Tax	34,167	36,489	(10,108)	26,382	(7,786)	
7	Add (Deduct) - Timing Differences	(6,388)	(5,740)	-	(5,740)	648	Schedule 33
8	Taxable Income After Tax	$27,779	$30,750	($10,108)	$20,642	($7,137)	
9		30.000%	30.000%	30.000%	30.000%	0.000%	
10	1 - Current Income Tax Rate	70.000%	70.000%	70.000%	70.000%	0.000%	
11	Taxable Income	$39,685	$43,928	($14,439)	$29,489	($10,196)	
12	**Total Income Tax**	$ 11,905	$ 13,178	$ (4,332)	$ 8,847	$ (3,058)	x-ref Schedule 2

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 6

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 ----Cost of Service Rates----- Approved Rates	Required Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return After VINGPA Adjustment	$35,687	$67,484	($30,467)	$37,017	$1,330	Schedule 3
3	Deduct - Interest on Debt	(17,755)	(18,574)	11	(18,563)	(808)	Schedule 12
4	Add - O&M Savings	2,435	-	-	-	(2,435)	
5	Add- Non-Tax Ded. Expense (Net)	6,015	(6,593)	-	(6,593)	(12,608)	Schedule 34
6	Accounting Income After Tax	26,382	42,316	(30,455)	11,860	(14,521)	
7	Add (Deduct) - Timing Differences	(5,740)	(8,044)	-	(8,044)	(2,304)	Schedule 34
8	Taxable Income After Tax	$20,642	$34,272	($30,455)	$3,816	($16,826)	
9		30.000%	28.500%	28.500%	28.500%	-1.500%	
10	1 - Current Income Tax Rate	70.000%	71.500%	71.500%	71.500%	1.500%	
11	Taxable Income	$29,489	$47,933	($42,595)	$5,338	($24,151)	
12	**Total Income Tax**	$ 8,847	$ 13,661	$ (12,140)	$ 1,521	$ (7,326)	x-ref Schedule 3

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 7

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 ----Cost of Service Rates----- Approved Rates	Required Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return After VINGPA Adjustment	$37,017	$69,086	($18,087)	$50,999	$13,982	Schedule 4
3	Deduct - Interest on Debt	(18,563)	(26,136)	10	(26,126)	(7,563)	Schedule 13
4	Add - O&M Savings	-	-	-	-	-	
5	Add- Non-Tax Ded. Expense (Net)	(6,593)	(686)	-	(686)	5,908	Schedule 35
6	Accounting Income After Tax	11,860	42,264	(18,077)	24,187	12,327	
7	Add (Deduct) - Timing Differences	(8,044)	(13,552)	-	(13,552)	(5,509)	Schedule 35
8	Taxable Income After Tax	$3,816	$28,712	($18,077)	$10,635	$6,818	
9		28.500%	26.500%	26.500%	26.500%	-2.000%	
10	1 - Current Income Tax Rate	71.500%	73.500%	73.500%	73.500%	2.000%	
11	Taxable Income	$5,338	$39,064	($24,595)	$14,469	$340,924	
12	**Total Income Tax**	$ 1,521	$ 10,352	$ (6,518)	$ 3,834	$ 2,313	x-ref Schedule 4

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 8

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars (1)	2009 APPROVED (2)	2009 Approved Rates (3)	2009 Adjustments (4)	2009 Cost of Service Rates (5)	Change (6)	Reference (7)
1	Gas Plant in Service, Beginning	$ 737,301	$ 733,157	$ -	$ 733,157	$ (4,144)	Schedule 44
2	Opening Balance Adjustment*	-	208,237	-	208,237	208,237	
3	Gas Plant in Service, Ending	785,862	1,012,319	-	1,012,319	226,458	Schedule 44
4	Accumulated Depreciation Beginning - Plant	(178,559)	(178,029)	-	(178,029)	530	Schedule 50
5	Opening Balance Adjustment*	-	(45,847)	-	(45,847)	(45,847)	
6	Accumulated Depreciation Ending - Plant	(196,352)	(245,154)	-	(245,154)	(48,802)	Schedule 50
7	CIAC, Beginning	(60,835)	(60,835)	-	(60,835)	(0)	Schedule 55
8	Opening Balance Adjustment*		(208,237)	-	(208,237)	(208,237)	
9	CIAC, Ending	(53,475)	(278,861)	-	(278,861)	(225,386)	Schedule 55
10	Accumulated Amortization Beginning - CIAC	1,990	1,990	-	1,990	(0)	Schedule 55
11	Opening Balance Adjustment*		45,847	-	45,847	45,847	
12	Accumulated Amortization Ending - CIAC	-	50,380	-	50,380	50,380	Schedule 55
13	Net Plant in Service, Mid-Year	$ 517,966	$ 517,483	$ -	$ 517,483	$ (482)	
14	Adjustment to 13-Month Average	817	6,489	-	6,489	5,672	
15	Allocated Common Plant to TGW, Mid-Year	(104)	(104)	-	(104)	0	
16	Work in Progress, No AFUDC	1,812	3,652	-	3,652	1,840	
17	Unamortized Deferred Charges	6,246	3,689	-	3,689	(2,557)	Schedule 58
18	Cash Working Capital	(2,100)	(2,589)	(407)	(2,996)	(895)	Schedule 61
19	Other Working Capital (incl. Construction Advances)	14,889	11,575	-	11,575	(3,313)	Schedule 61
20	Future Income Taxes Regulatory Asset	-	58,802	-	58,802	58,802	Schedule 67
21	Future Income Taxes Liability	-	(58,802)	-	(58,802)	(58,802)	Schedule 67
22	**Utility Rate Base**	$ 539,525	$ 540,195	$ (407)	$ 539,788	$ 264	

*Adjustment to remove CIAC from Gas Plant in Service, and Accumulated Amortization of CIAC from Accumulated Depreciaton

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
Tab 13
Schedule 9

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Approved Rates	2010 Adjustments	2010 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 733,157	$ 1,012,319	$ -	$ 1,012,319	$ 279,162	Schedule 46
2	Opening Balance Adjustment	208,237	-	-	-	(208,237)	
3	Gas Plant in Service, Ending	1,012,319	1,036,234	-	1,036,234	23,915	Schedule 46
4	Accumulated Depreciation Beginning - Plant	(178,029)	(245,154)	-	(245,154)	(67,125)	Schedule 52
5	Opening Balance Adjustment*	(45,847)	(1,379)	-	(1,379)	44,468	
6	Accumulated Depreciation Ending - Plant	(245,154)	(270,987)	-	(270,987)	(25,833)	Schedule 52
7	CIAC, Beginning	(60,835)	(278,861)	-	(278,861)	(218,026)	Schedule 56
8	Opening Balance Adjustment	(208,237)	-	-	-	208,237	
9	CIAC, Ending	(278,861)	(275,728)	-	(275,728)	3,133	Schedule 56
10	Accumulated Amortization Beginning - CIAC	1,990	50,380	-	50,380	48,390	Schedule 56
11	Opening Balance Adjustment	45,847	-	-	-	(45,847)	
12	Accumulated Amortization Ending - CIAC	50,380	54,795	-	54,795	4,415	Schedule 56
13	Net Plant in Service, Mid-Year	$ 517,483	$ 540,809	$ -	$ 540,809	$ 23,326	
14	Adjustment to 13-Month Average	6,489	-	-	-	(6,489)	
15	Allocated Common Plant to TGW, Mid-Year	(104)	-	-	-	104	
16	Work in Progress, No AFUDC	3,652	3,608	-	3,608	(44)	
17	Unamortized Deferred Charges	3,689	495	-	495	(3,194)	Schedule 59
18	Cash Working Capital	(2,996)	318	(750)	(432)	2,563	Schedule 62
19	Other Working Capital (incl. Construction Advances)	11,575	9,533	-	9,533	(2,043)	Schedule 62
20	Future Income Taxes Regulatory Asset	58,802	60,101	-	60,101	1,298	Schedule 67
21	Future Income Taxes Liability	(58,802)	(60,101)	-	(60,101)	(1,298)	Schedule 67
22	**Utility Rate Base**	$ 539,788	$ 554,763	$ (750)	$ 554,013	$ 14,224	

*Adjustment relates to transfer of accumulated loss on General Plant to IFRS Transitional Adjustments deferral account

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 10

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Approved Rates	2011 Adjustments	2011 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 1,012,319	$ 1,036,234	$ -	$ 1,036,234	$ 23,915	Schedule 48
2	Opening Balance Adjustment	-	-	-	-	-	
3	Gas Plant in Service, Ending	1,036,234	1,274,815	-	1,274,815	238,581	Schedule 48
4	Accumulated Depreciation Beginning - Plant	(245,154)	(270,987)	-	(270,987)	(25,833)	Schedule 54
5	Opening Balance Adjustment	(1,379)	-	-	-	1,379	
6	Accumulated Depreciation Ending - Plant	(270,987)	(299,264)	-	(299,264)	(28,277)	Schedule 54
7	CIAC, Beginning	(278,861)	(275,728)	-	(275,728)	3,133	Schedule 57
8	Opening Balance Adjustment	-	-	-	-	-	
9	CIAC, Ending	(275,728)	(276,176)	-	(276,176)	(448)	Schedule 57
10	Accumulated Amortization Beginning - CIAC	50,380	54,795	-	54,795	4,415	Schedule 57
11	Opening Balance Adjustment	-	-	-	-	-	
12	Accumulated Amortization Ending - CIAC	54,795	59,218	-	59,218	4,423	Schedule 57
13	Net Plant in Service, Mid-Year	$ 540,809	$ 651,454	$ -	$ 651,454	$ 110,644	
						0	
14	Adjustment to 13-Month Average	-	56,712	-	56,712	56,712	
15	Allocated Common Plant to TGW, Mid-Year	-	-	-	-	-	
16	Work in Progress, No AFUDC	3,608	3,608	-	3,608	-	
17	Unamortized Deferred Charges	495	4,908	-	4,908	4,413	Schedule 60
18	Cash Working Capital	(432)	516	(381)	135	567	Schedule 63
19	Other Working Capital (incl. Construction Advances)	9,533	12,178	-	12,178	2,645	Schedule 63
20	Future Income Taxes Regulatory Asset	60,101	63,889	-	63,889	3,788	Schedule 67
21	Future Income Taxes Liability	(60,101)	(63,889)	-	(63,889)	(3,788)	Schedule 67
22	**Utility Rate Base**	$ 554,013	$ 729,375	$ (381)	$ 728,994	$ 174,982	

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 11

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	Reference	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	APPROVED RATES								
2	Long-Term Debt			$260,940	48.300%	5.956%	2.880%	15,541	x-ref Schedule 5
3	Unfunded Debt			63,177	11.700%	1.500%	0.180%	948	x-ref Schedule 5
4	Common Equity			216,078	40.000%	13.841%	5.536%	29,907	
5	Before Sub Debt Interest	Schedule 39		$540,195	100.000%		8.596%	$46,396	
6	Sub Debt Interest							1,270	x-ref Schedule 5
7	Total						8.824%	$47,666	
8	2009 COST OF SERVICE RATES - PROJECTION								
9	Long-Term Debt			$260,940	48.340%	5.956%	2.880%	15,541	x-ref Schedule 5
10	Unfunded Debt		$63,177						
11	Adjustment, Revised Rates		(244)	62,933	11.660%	1.500%	0.170%	944	x-ref Schedule 5
13	Common Equity			215,915	40.000%	9.170%	3.670%	19,799	
14	Before Sub Debt Interest	Schedule 39		$539,788	100.000%		6.720%	36,284	x-ref Schedule 5
15	Sub Debt Interest							1,270	
16							6.957%	37,554	x-ref Schedule 2, 5, 14

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 12

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Reference	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	APPROVED RATES								
2	Long-Term Debt			$289,659	52.210%	5.950%	3.110%	17,233	x-ref Schedule 6
3	Unfunded Debt			43,199	7.790%	2.500%	0.190%	1,080	x-ref Schedule 6
4	Common Equity			221,905	40.000%	22.882%	9.153%	50,776	
5		Schedule 40		$554,763	100.000%		12.453%	$69,089	
6								261	x-ref Schedule 6
7							12.501%	$69,350	
8	2010 COST OF SERVICE RATES								
9	Long-Term Debt			$289,659	52.280%	5.950%	3.110%	17,233	x-ref Schedule 6
10	Unfunded Debt		$43,199						
11	Adjustment, Revised Rates		(450)	42,749	7.720%	2.500%	0.190%	1,069	x-ref Schedule 6
13	Common Equity			221,605	40.000%	9.170%	3.670%	20,321	
14		Schedule 40		$554,013	100.000%		6.970%	38,623	x-ref Schedule 6
15								261	
16							7.019%	38,884	x-ref Schedule 3, 6, 14

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 13

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Reference	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	APPROVED RATES								
2	Long-Term Debt			$390,731	53.570%	6.119%	3.278%	23,909	x-ref Schedule 7
3	Unfunded Debt			46,894	6.430%	4.750%	0.305%	2,227	x-ref Schedule 7
4	Common Equity			291,750	40.000%	15.361%	6.145%	44,816	
5		Schedule 41							
6									
7				$729,375	100.000%		9.728%	$70,953	
8	2011 COST OF SERVICE RATES								
9	Long-Term Debt			$390,731	53.600%	6.119%	3.280%	23,909	x-ref Schedule 7
10	Unfunded Debt		$46,894						
11	Adjustment, Revised Rates		(229)	46,665	6.400%	4.750%	0.304%	2,217	x-ref Schedule 7
13	Common Equity			291,598	40.000%	9.170%	3.668%	26,740	
14		Schedule 41							
15									
16				$728,994	100.000%		7.252%	52,866	x-ref Schedule 4, 7, 14

UTILITY INCOME AND EARNED RETURN
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009 Approved Rates	2009 Surplus	2009 Cost of Service Rates	2010 Approved Rates	2010 Surplus	2010 Cost of Service Rates	2011 Approved Rates	2011 Surplus	2011 Cost of Service Rates	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	ENERGY VOLUMES (TJ)										
2	Sales	12,264	-	12,264	12,241	-	12,241	12,433	-	12,433	Schedules 15, 16, 17
3	Transportation	22,946	-	22,946	22,309	-	22,309	22,017	-	22,017	Schedules 15, 16, 17
4		35,210	-	35,210	34,550	-	34,550	34,450	-	34,450	
5	Average Rate per GJ										
6	Sales	$14.636		$13.459	$14.659		$11.179	$14.671		$12.692	
7	Transportation	$0.967		$0.967	$0.926		$0.926	$0.931		$0.931	
8	Average	$5.728		$5.318	$5.792		$4.559	$5.890		$5.176	
9	Sales - Present Rates	$179,501	$0	$179,501	$179,445	$0	$179,445	$182,402	$0	$182,402	Schedules 18, 19, 20
10	- Increase / (Decrease)	-	(14,443)	(14,443)	-	(42,605)	(42,605)	-	(24,603)	(24,603)	
11	Transportation - Present Rates	22,194	-	22,194	20,669	-	20,669	20,500	-	20,500	Schedules 18, 19, 20
12	- Increase / (Decrease)	-	-	-	-	-	-	-	-	-	
13	Total Revenue	201,695	(14,443)	187,252	200,114	(42,606)	157,508	202,902	(24,603)	178,299	
14	Royalty Credit	(28,095)	-	(28,095)	(35,832)	-	(35,832)	(40,091)	-	(40,091)	
15	GCVA Amortization	4,162		4,162	(4,047)		(4,047)	-	-	-	
16	GCVA Additions	5,781	-	5,781	-	-	-	-	-	-	
17	Cost of Gas	99,314	-	99,314	98,628	-	98,628	107,311	-	107,311	Schedule 21
18	RACOG Including GCVA Impacts	81,162	-	81,162	58,750	-	58,750	67,220	-	67,220	
19	Gross Margin	120,533	(14,443)	106,090	141,364	(42,606)	98,758	135,682	(24,603)	111,079	
20	Operation and Maintenance	26,178	-	26,178	26,858	-	26,858	28,136	-	28,136	
21	Transportation Expenses	3,977	-	3,977	4,015	-	4,015	4,122	-	4,122	
22	Operating Leases	828	-	828	-	-	-	-	-	-	
23	Property and Sundry Taxes	8,449	-	8,449	9,119	-	9,119	9,564	-	9,564	Schedule 26
24	Depreciation and Amortization	23,017	-	23,017	19,202	-	19,202	25,232	-	25,232	Schedules 27, 28, 29
25	Removal Costs (Depreciation)	-	-	-	343	-	343	344	-	344	
26	IFRS Transitional Deferral	-	-	-	1,400	-	1,400	(1,400)	-	(1,400)	
27	Other Operating Revenue	(893)	-	(893)	(717)	-	(717)	(9,752)	-	(9,752)	Schedule 22
28		61,556	-	61,556	60,220	0	60,220	56,246	-	56,246	
29	Utility Income Before Income Taxes	58,977	(14,443)	44,534	81,144	(42,606)	38,538	79,437	(24,604)	54,833	
30	Income Taxes	13,178	(4,331)	8,847	13,661	(12,140)	1,521	10,352	(6,518)	3,834	Schedules 30, 31, 32
33	EARNED RETURN after VINGPA Adjustment	45,799	($10,112)	$35,687	$67,483	($30,466)	$37,017	$69,085	($18,086)	$50,999	
34	UTILITY RATE BASE	$540,195	($407)	$539,788	$554,763	($750)	$554,013	$729,375	($381)	$728,994	Schedules 39, 40, 41
35	RATE OF RETURN ON UTILITY RATE BASE										
36	Before VINGPA Adjustment	8.82%		6.96%	12.50%		7.02%	9.73%		7.25%	
37	AFter VINGPA Adjustment	8.48%		6.61%	12.16%		6.68%	9.47%		7.00%	
38	EARNED RETURN	47,666	(10,112)	37,554	69,350	(30,466)	38,884	70,952	(18,086)	52,866	
39	VINGPA Adjustment	(1,867)	-	(1,867)	(1,867)	-	(1,867)	(1,867)	-	(1,867)	
40	EARNED RETURN after VINGPA Adjustment	45,799	(10,112)	35,687	67,483	(30,466)	37,017	69,085	(18,086)	50,999	

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 15

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2009

Line No.	Particulars	2009 APPROVED	2009 Terajoules: Core and Non-Core	2009 Terajoules: Special Rates	2009 Terajoules: Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Core						
2	RGS	5,116.8	4,859.0	0.0	4,859.0	(257.8)	
3	AGS	1,150.8	1,129.6		1,129.6	(21.2)	
4	SCS1	361.1	446.5		446.5	85.4	
5	SCS2	548.9	501.4		501.4	(47.5)	
6	LCS1	1,362.4	1,344.4		1,344.4	(18.0)	
7	LCS2	1,265.1	1,314.9		1,314.9	49.8	
8	LCS3	2,535.6	2,421.9		2,421.9	(113.7)	
9	Residential & Commercial sub-total	12,340.7	12,017.7	0.0	12,017.7	(323.0)	
10	HLF	175.5	129.2		129.2	(46.3)	
11	ILF	119.7	117.1		117.1	(2.6)	
12	Total Core	12,635.9	12,264.0	0.0	12,264.0	(371.9)	x-ref Schedule 2, 14
13	Transportation Service						
14	BCH	16,425.0	16,567.9	0.0	16,567.9	142.9	
15	TGW	1,919.6	1,875.5	0.0	1,875.5	(44.1)	
16	VIGJV	2,920.0	0.0	4,098.0	4,098.0	1,178.0	
17	TG Squamish	427.8	0.0	404.7	404.7	(23.1)	
18	Total Transportation Service	21,692.4	18,443.4	4,502.7	22,946.1	1,253.7	x-ref Schedule 2, 14
19	**TOTAL SALES AND TRANSPORTATION SERVICES**	34,328.2	30,707.4	4,502.7	35,210.1	881.9	

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement

Section C
Tab 13
Schedule 16

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2010

Line No.	Particulars	2009 PROJECTION	2010 Terajoules: Core and Non-Core	2010 Terajoules: Special Rates	2010 Terajoules: Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Core						
2	RGS	4,859.0	4,891.8	0.0	4,891.8	32.8	
3	AGS	1,129.6	1,110.3		1,110.3	(19.3)	
4	SCS1	446.5	406.2		406.2	(40.3)	
5	SCS2	501.4	483.7		483.7	(17.7)	
6	LCS1	1,344.4	1,329.4		1,329.4	(15.0)	
7	LCS2	1,314.9	1,383.5		1,383.5	68.6	
8	LCS3	2,421.9	2,383.5		2,383.5	(38.4)	
9	Residential & Commercial sub-total	12,017.7	11,988.4	0.0	11,988.4	(29.3)	
10	HLF	129.2	132.4		132.4	3.2	
11	ILF	117.1	120.5		120.5	3.4	
12	Total Core	12,264.0	12,241.3	0.0	12,241.3	(22.7)	x-ref Schedule 3, 14
13	Transportation Service						
14	BCH	16,567.9	18,250.0	0.0	18,250.0	1,682.1	
15	TGW	1,875.5	725.2	0.0	725.2	(1,150.3)	
16	VIGJV	4,098.0	0.0	2,920.0	2,920.0	(1,178.0)	
17	TG Squamish	404.7	0.0	413.4	413.4	8.7	
18	Total Transportation Service	22,946.1	18,975.2	3,333.4	22,308.6	(637.5)	x-ref Schedule 3, 14
19	**TOTAL SALES AND TRANSPORTATION SERVICES**	35,210.1	31,216.5	3,333.4	34,549.9	(660.2)	

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 17

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2011

Line No.	Particulars	2010 FORECAST	2011 Terajoules Core and Non-Core	2011 Terajoules Special Rates	2011 Terajoules Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Core						
2	RGS	4,891.8	5,015.3	0.0	5,015.3	123.5	
3	AGS	1,110.3	1,116.6		1,116.6	6.3	
4	SCS1	406.2	414.4		414.4	8.2	
5	SCS2	483.7	485.2		485.2	1.5	
6	LCS1	1,329.4	1,334.2		1,334.2	4.8	
7	LCS2	1,383.5	1,396.8		1,396.8	13.3	
8	LCS3	2,383.5	2,417.2		2,417.2	33.7	
9	Residential & Commercial sub-total	11,988.4	12,179.7	0.0	12,179.7	191.3	
10	HLF	132.4	132.4		132.4	0.0	
11	ILF	120.5	120.5		120.5	0.0	
12	Total Core	12,241.3	12,432.6	0.0	12,432.6	191.3	x-ref Schedule 4, 14
13	Transportation Service						
14	BCH	18,250.0	17,945.0	0.0	17,945.0	(305.0)	
15	TGW	725.2	729.9	0.0	729.9	4.7	
16	VIGJV	2,920.0	0.0	2,920.0	2,920.0	0.0	
17	TG Squamish	413.4	0.0	422.3	422.3	8.9	
18	Total Transportation Service	22,308.6	18,674.9	3,342.3	22,017.2	(291.4)	x-ref Schedule 4, 14
19	**TOTAL SALES AND TRANSPORTATION SERVICES**	34,549.9	31,107.5	3,342.3	34,449.8	(100.1)	

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
Tab 13
Schedule 18

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Gas Sales Revenue At Approved Rates: Core and Transportation	Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**Core Sales**						
2	RGS	$84,300	$80,487	$0	$80,487	($3,813)	
3	AGS	14,644	14,399		14,399	(245)	
4	SCS1	6,627	8,113		8,113	1,486	
5	SCS2	9,738	8,826		8,826	(912)	
6	LCS1	19,264	18,902		18,902	(362)	
7	LCS2	16,203	16,740		16,740	537	
8	LCS3	30,811	29,410		29,410	(1,401)	
9	Residential & Commercial sub-total	181,588	176,878	-	176,878	(4,710)	
10	HLF	1,975	1,417	-	1,417	(557)	
11	ILF	1,233	1,206		1,206	(26)	
		3,207	2,624	-	2,624	(584)	
12	Total Core Sales	184,795	179,501	-	179,501	(5,294)	x-ref Schedules 2, 14
13	Transportation Service						
14	BCH	$14,980	16,189	-	16,189	1,209	
15	TGW	1,970	1,739	-	1,739	(230)	
16	VIGJV	2,727	-	3,841	3,841	1,114	
17	TG Squamish	449	-	425	425	(24)	
18	Total Core and Transportation Service	20,126	17,928	4,266	22,194	2,069	x-ref Schedules 2, 14
19	TOTAL SALES AND TRANSPORTATION SERVICE	$204,921	$197,430	$4,266	$201,696	($3,225)	x-ref Schedules 65

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 19

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Gas Sales Revenue At Approved Rates: Core and Transportation	Special Rates	Total	Change	Reference	$'s per GJ (effective rates)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Core Sales**							
2	RGS	$80,487	$81,286	$0	$81,286	$799		$16.617
3	AGS	14,399	14,160		14,160	(239)		12.753
4	SCS1	8,113	7,461		7,461	(651)		18.369
5	SCS2	8,826	8,518		8,518	(307)		17.611
6	LCS1	18,902	18,744		18,744	(159)		14.099
7	LCS2	16,740	17,646		17,646	905		12.754
8	LCS3	29,410	28,931		28,931	(479)		12.138
9	Residential & Commercial sub-total	176,878	176,746	-	176,746	(132)		
10	HLF	1,417	1,459	-	1,459	41		11.018
11	ILF	1,206	1,241		1,241	34		10.296
		2,624	2,699	-	2,699	76		
12	Total Core Sales	179,501	179,445	-	179,445	(56)	x-ref Schedules 3, 14	
13	Transportation Service							
14	BCH	16,189	15,148	-	15,148	(1,041)		0.830
15	TGW	1,739	2,359	-	2,359	620		3.253
16	VIGJV	3,841	-	2,728	2,728	(1,113)		0.934
17	TG Squamish	425	-	434	434	9		1.050
18	Total Core and Transportation Service	22,194	17,507	3,162	20,669	(1,525)	x-ref Schedules 3, 14	
19	TOTAL SALES AND TRANSPORTATION SERVICE	$201,696	$196,952	$3,162	$200,114	($1,581)	x-ref Schedules 65	

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 20

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Gas Sales Revenue At Approved Rates: Core and Transportation	Special Rates	Total	Change	Reference	$'s per GJ (effective rates)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Core Sales**							
2	RGS	$81,286	$83,340	$0	$83,340	$2,053		$16.617
3	AGS	14,160	14,240		14,240	80		12.753
4	SCS1	7,461	7,612		7,612	151		18.370
5	SCS2	8,518	8,546		8,546	28		17.614
6	LCS1	18,744	18,812		18,812	68		14.100
7	LCS2	17,646	17,814		17,814	169		12.754
8	LCS3	28,931	29,337		29,337	407		12.137
9	Residential & Commercial sub-total	176,746	179,703	-	179,703	2,957		
10	HLF	1,459	1,459	-	1,459	-		11.018
11	ILF	1,241	1,241		1,241	-		10.296
		2,699	2,699	-	2,699	-		
12	Total Core Sales	179,445	182,402	-	182,402	2,957	x-ref Schedules 4, 14	
13	Transportation Service							
14	BCH	15,148	14,894	-	14,894	(253)		0.830
15	TGW	2,359	2,386	-	2,386	27		3.269
16	VIGJV	2,728	-	2,776	2,776	48		0.951
17	TG Squamish	434	-	443	443	9		1.050
18	Total Core and Transportation Service	20,669	17,281	3,219	20,500	(169)	x-ref Schedules 4, 14	
19	TOTAL SALES AND TRANSPORTATION SERVICE	$200,114	$199,683	$3,219	$202,902	$2,788	x-ref Schedules 65	

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
COST OF GAS Schedule 21
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009 Gas Costs Core and Non-Core	2009 Special Rates	2009 Total	2010 Gas Costs Core and Non-Core	2010 Special Rates	2010 Total	2011 Gas Costs Core and Non-Core	2011 Special Rates	2011 Total	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
1	**Core**										
2	RGS	39,348	$0	$39,348	$39,414	$0	$39,414	43,289	$0	$43,289	
3	AGS	9,147		9,147	8,946		8,946	9,638		9,638	
4	SCS1	3,616		3,616	3,272		3,272	3,577		3,577	
5	SCS2	4,061		4,061	3,897		3,897	4,188		4,188	
6	LCS1	10,887		10,887	10,711		10,711	11,516		11,516	
7	LCS2	10,648		10,648	11,147		11,147	12,056		12,056	
8	LCS3	19,613		19,613	19,204		19,204	20,864		20,864	
9	Residential & Commercial sub-total	97,320	-	97,320	96,591	-	96,591	105,128	-	105,128	
10	HLF	1,046		1,046	1,066		1,066	1,143		1,143	
11	ILF	948		948	971		971	1,040		1,040	
12	Industrial Subtotal	1,994	-	1,994	2,037	-	2,037	2,183	-	2,183	
13	Total Core	99,314	-	99,314	98,628	-	98,628	107,311	-	107,311	x-ref Schedules 2, 3, 4, 14
14	Unit Cost of Gas before Royalty Credit and GCVA	$8.098		$8.098	$8.057		$8.057	$8.631		$8.631	

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
Schedule 22

OTHER OPERATING REVENUE
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009	2010	2011	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Operating Revenue**				
2	Late Payment Charge	$368	$340	$345	
3	Connection Charge	519	370	380	
4	NSF Returned Cheque Charges	4	5	5	
5	Other Recoveries	2	2	2	
6	LNG Mitigation Revenue	0	0	9,020	
7	Total Other Operating Revenue	$893	$717	$9,752	x-ref Schedules 2, 3, 4, 14, 65

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 23

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
($000)

Line No.	Particulars	PROJECTION 2009	FORECAST 2010	FORECAST 2011	
	(1)	(3)	(4)	(5)	
1	M&E Costs	$ 3,996	$ 4,225	$ 3,868	
2	COPE Costs	63	109	110	
3	IBEW Costs	4,425	4,486	5,451	
4	**Labour Costs**	**8,484**	**8,819**	**9,429**	
5	Vehicle Costs	610	667	722	
6	Employee Expenses	522	567	587	
7	Materials and Supplies	956	1,338	1,395	
8	Computer Costs	379	302	231	
9	Fees and Administration Costs	8,868	11,387	11,911	
10	Contractor Costs	8,049	7,076	7,125	
11	Facilities	2,114	2,169	2,416	
12	Recoveries & Revenue	(962)	(1,093)	(1,115)	
13	**Non-Labour Costs**	**20,537**	**22,412**	**23,273**	
14	**Total Gross O&M Expenses**	**29,021**	**31,231**	**32,702**	
15	Allocation to Terasen Gas Whistler	(245)	-	-	
16	**Total Gross O&M Expenses net of allocation to TGW**	**28,776**	**31,231**	**32,702**	
17	Less: Capitalized Overhead	(5,033)	(4,372)	(4,567)	
18	**Total O&M Expenses**	**$ 23,743**	**$ 26,858**	**$ 28,136**	x-ref Schedules 3, 4, 14

Note: 2009 numbers are projected actual as opposed to approved

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C Tab 13 Schedule 24

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
($000s)

Line No.	Particulars	Reference	PROJECTION 2009	FORECAST 2010	FORECAST 2011
	(1)	(2)	(3)	(4)	(5)
1	*Operating*				
2	Distribution Supervision	100-11	$ 1,741	$ 1,909	$ 1,951
3	Distribution Supervision Total	100-10	1,741	1,909	1,951
4	Operation Centre - Distribution	100-21	(0)	507	526
5	Preventative Maintenance - Distribution	100-23	228	222	172
6	Distribution Operations - General	100-24	868	766	795
7	Meter Exchange	100-25	(0)	-	-
8	Emergency Management	100-26	1,285	1,217	1,266
9	Distribution Operations Total	100-20	2,380	2,712	2,759
10	Distribution Corrective - Meters	100-31	286	161	169
11	Distribution Corrective - Propane	100-32	-	-	-
12	Distribution Corrective - Leak Repair	100-33	151	135	139
13	Distribution Corrective - Stations	100-34	36	42	40
14	Distribution Corrective - General	100-35	124	72	75
15	Distribution Maintenance Total	100-30	597	409	422
16	**Distribution Total**	**100**	**4,719**	**5,030**	**5,132**
17	Pipeline Operation - Operations	200-21	2,013	1,439	1,346
18	Right of Way	200-22	157	172	175
19	Compression - Operations	200-23	942	1,074	1,004
20	Gas Control	200-24	-	-	-
21	Transmission - Operation	200-20	3,112	2,685	2,525
22	Pipeline Operation - Maintenance	200-31	511	589	610
23	Compression - Maintenance	200-33	1,322	614	671
24	Transmission - Maintenance	200-30	1,833	1,202	1,281
25	**Transmission Total**	**200**	**4,945**	**3,887**	**3,806**
26	**Mt. Hayes**	300-11	**-**	**395**	**1,685**
27	**LNG Total**	**300**	**-**	**395**	**1,685**
26	Measurement Operations	400-11	461	468	527
27	Measurement - Operation	400-10	461	468	527
28	Measurement Maintenance	400-21	591	603	603
29	Measurement - Maintenance	400-20	591	603	603
30	**Measurement**	**400**	**1,053**	**1,071**	**1,130**
31	Facilities Management	500-10	1,487	1,521	1,596
32	Operations Engineering	500-30	270	305	310
33	System Integrity	500-50	154	206	210
34	**General Operations Total**	**500**	**1,912**	**2,031**	**2,116**
35	**Total Operating**		**12,628**	**12,414**	**13,869**

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C Tab 13

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (CONT'D) Schedule 25
($000s)

Line No.	Particulars	Reference	PROJECTION 2009	FORECAST 2010	FORECAST 2011	
	(1)	(2)	(3)	(4)	(5)	
1	*General & Administration*					
2	Corporate & Marketing Communications	600-30	497	0	0	
3	**Marketing Total**	**600**	**497**	**0**	**0**	
4	Customer Care - Supervision	700-10	-	-	-	
5	Customer Contact - ABSU contract	700-20	5,133	5,277	5,480	
6	Bad Debt Management and Administration	700-30	482	259	276	
7	Customer Management & Sales	700-40	1,087	1,140	1,168	
8	**Customer Care Total**	**700**	**6,702**	**6,676**	**6,923**	
9	Application Management	800-20	584	433	438	
10	**Business & IT Services Total**	**800**	**584**	**433**	**438**	
11	Corporate Administration	900-10	7,310	10,076	10,345	
12	Public Affairs	900-30	177	270	270	
13	Human Resource	900-50	-	-	-	
14	Other Post Employment Benefit	900-60	1,123	1,362	858	
15	**Administration & General Total**	**900**	**8,610**	**11,708**	**11,473**	
16	**Total General & Administration**		**16,393**	**18,817**	**18,834**	
17	**Total Gross O&M Expenses**		**29,021**	**31,231**	**32,702**	
18	Allocation to Terasen Gas Whistler		(245)	-	-	
19	**Total Gross O&M Expenses net of allocation to TGW**		**28,776**	**31,231**	**32,702**	
20	Less: Capitalized Overhead		(5,033)	(4,372)	(4,567)	
21	**Total O&M Expenses**		**$ 23,743**	**$ 26,858**	**$ 28,136**	x-ref Schedules 3, 4, 14

Note: 2009 numbers are projected actual as opposed to approved

PROPERTY AND SUNDRY TAXES
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009 Expenses	2010 Expenses	2011 Expenses	
	(1)	(3)	(4)	(5)	
1	Property Taxes				
2	1% in Lieu of General Municipal Tax	$1,522	$1,652	$1,655	
3	General, School and Other	6,927	7,468	7,909	
4	Total	$8,449	$9,119	$9,564	x-ref Schedules 2, 3, 4, 14

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
Schedule 27

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Projection	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation Provision**				
2	Total Depreciation Expense	$19,242	$23,798	$4,556	Schedule 50
4	Less: Depreciation Expense Allocated to TGW	(22)	(22)	-	
5	Less: Amortization of Contributions in Aid of Construction	1,990	(2,545)	(4,535)	Schedule 55
6		21,210	21,231	21	
7	**Amortization Expense**				
8	Amortization of Deferred Charges	$4,790	$5,949	$1,158	Schedule 58
9	Amortization of RDDA	9,275	-	(9,275)	
10	Amortization Expense Including GCVA	14,065	5,949	(8,117)	
11	Less: GCVA (Cost of Gas Item)	(3,045)	(4,162)	($1,117)	Schedule 58
12	Adjusted Total Amoritzation Expense	11,020	1,787	(9,234)	
13	TOTAL	$32,230	$23,017	($9,213)	x-ref Schedules 2, 14. 33

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
Tab 13
Schedule 28

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Forecast	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation Provision**				
2	Total Depreciation Expense	$23,798	$26,231	$2,432	Schedule 52
4	Less: Depreciation Expense Allocated to TGW	(22)	-	(22)	
5	Less: Amortization of Contributions in Aid of Construction	(2,545)	(4,415)	(1,870)	Schedule 56
6		21,231	21,816	562	
7	**Amortization Expense**				
8	Amortization of Deferred Charges	$5,949	($5,179)	($11,128)	Schedule 59
9	Amortization of 2009 Revenue Surplus	-	(1,481)	(1,481)	Schedule 59
10		5,949	(6,660)	(12,609)	
11	Less: GCVA (Cost of Gas Item)	(4,162)	4,047	8,209	Schedule 59
12	Adjusted Total Amoritzation Expense	1,787	(2,614)	(4,400)	
13	TOTAL	$23,017	$19,202	($3,816)	x-ref Schedules 3, 14, 34

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
Tab 13
Schedule 29

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Forecast	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation Provision**				
2	Total Depreciation Expense	$26,231	$30,409	$4,179	Schedule 54
4	Less: Depreciation Expense Allocated to TGW	-	-	-	
5	Less: Amortization of Contributions in Aid of Construction	(4,415)	(4,423)	(8)	Schedule 57
6		21,816	25,986	4,171	
7	**Amortization Expense**				
8	Amortization of Deferred Charges	($5,179)	$727	$5,907	Schedule 60
9	Amortization of 2009 Revenue Surplus	(1,481)	(1,481)	-	Schedule 60
10		(6,660)	(754)	5,907	
11	Less: GCVA (Cost of Gas Item)	4,047	-	(4,047)	Schedule 60
12	Adjusted Total Amoritzation Expense	(2,614)	(754)	1,860	
13	TOTAL	$19,202	$25,232	6,030	x-ref Schedules 4, 14, 35

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
INCOME TAXES Schedule 30
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Approved Rates	2009 Cost of Service Rates	2009 Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return After VINGPA Adjustment	$36,756	$45,799	($10,112)	$35,687	($1,069)	Schedule 2
3	Deduct - Interest on Debt	(20,325)	(17,759)	4	(17,755)	2,570	
4	Add - O&M Savings	2,127	2,435	-	2,435	308	
5	Add- Non-Tax Ded. Expense (Net)	15,609	6,015	-	6,015	(9,595)	Schedule 33
6	Accounting Income After Tax	34,167	36,489	(10,108)	26,382	(7,786)	
7	Add (Deduct) - Timing Differences	(6,388)	(5,740)	-	(5,740)	648	Schedule 33
8	Taxable Income After Tax	$27,779	$30,750	($10,108)	20,642	($7,137)	
9		30.000%	30.000%	30.000%	30.000%	0.000%	
10	1 - Current Income Tax Rate	70.000%	70.000%	70.000%	70.000%	0.000%	
11	Taxable Income	$39,685	$43,928	($14,439)	$29,489	($10,196)	
12	Income Tax - Current	$11,905	$13,178	($4,331)	$8,847	($3,058)	
13	Income Tax - Deferred	-	-	-		-	
12	**Total Income Tax**	$11,905	$13,178	($4,331)	$8,847	$26,331	x-ref Schedules 2, 14

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 31

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Approved Rates	2010 Cost of Service Rates	2010 Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return After VINGPA Adjustment	$35,687	$67,483	($30,466)	$37,017	$1,330	Schedule 3
3	Deduct - Interest on Debt	(17,755)	(18,574)	11	(18,563)	(808)	
4	Add - O&M Savings	2,435	-	-	-	(2,435)	
5	Add- Non-Tax Ded. Expense (Net)	6,015	(6,593)	-	(6,593)	(12,608)	Schedule 34
6	Accounting Income After Tax	26,382	42,316	(30,455)	11,860	(14,521)	
7	Add (Deduct) - Timing Differences	(5,740)	(8,044)	-	(8,044)	(2,304)	Schedule 34
8	Taxable Income After Tax	$20,642	$34,272	($30,455)	3,816	($16,826)	
9		30.000%	28.500%	28.500%	28.500%	-1.500%	
10	1 - Current Income Tax Rate	70.000%	71.500%	71.500%	71.500%	1.500%	
11	Taxable Income	$29,489	$47,933	($42,595)	$5,338	($24,151)	
12	Income Tax - Current	$8,847	$13,661	($12,140)	$1,521	($7,326)	
13	Income Tax - Deferred	-	-	-		-	
12	**Total Income Tax**	$8,847	$13,661	($12,140)	$1,521	($7,326)	x-ref Schedules 3, 14

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
Tab 13
INCOME TAXES | Schedule 32
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Approved Rates	2011 Cost of Service Rates	2011 Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return After VINGPA Adjustment	$37,017	$69,085	($18,086)	$50,999	$13,982	Schedule 4
3	Deduct - Interest on Debt	(18,563)	(26,136)	10	(26,126)	(7,563)	
4	Add - O&M Savings	-	-	-	-	-	
5	Add- Non-Tax Ded. Expense (Net)	(6,593)	(686)	-	(686)	5,908	Schedule 35
6	Accounting Income After Tax	11,860	42,263	(18,076)	24,187	12,327	
7	Add (Deduct) - Timing Differences	(8,044)	(13,552)	-	(13,552)	(5,509)	Schedule 35
8	Taxable Income After Tax	$3,816	$28,711	($18,076)	$10,635	$6,818	
9		28.500%	26.500%	26.500%	26.500%	-2.000%	
10	1 - Current Income Tax Rate	71.500%	73.500%	73.500%	73.500%	2.000%	
11	Taxable Income	$5,338	$39,062	($24,593)	$14,469	$340,924	
12	Income Tax - Current	$1,521	$10,351	($6,517)	$3,834	$2,313	
13	Income Tax - Deferred	-	-	-		-	
12	**Total Income Tax**	$1,521	$10,351	($6,517)	$3,834	$2,313	x-ref Schedules 4, 14

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
NON-TAX DEDUCTIBLE EXPENSES (NET) AND TIMING DIFFERENCE ADJUSTMENTS Schedule 33
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Projection	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**ITEMS OF A PERMANENT NATURE**				
2	Amortization of Deferred Charges	$15,557	5,949	($9,609)	Schedule 27
3	Non-tax Deductible Expenses	52	66	14	
4	Total Permanent Differences	$15,609	6,015	($9,595)	x-ref Schedule 5, 30
5	**TIMING DIFFERENCE ADJUSTMENTS**				
6	Depreciation	$19,242	$23,798	$4,556	Schedule 27
7	Amortization of Debt Issue Expenses	2,161	26	($2,135)	
8	Transmission Pipeline Inspection Costs	-	-	$0	
9	Debt Issue Costs	(606)	(548)	58	
10	Capital Cost Allowance	(22,805)	(23,741)	(936)	Schedule 36
11	Cumulative Eligible Capital Allowance	(375)	(398)	(23)	
12	Taxable Capital Gain	-	2,859	2,859	
13	Pension & OPEB Expense Booked	2,237	2,237	-	
14	Pension & OPEB Contributions	(1,579)	(1,888)	(309)	
15	Overheads Capitalized Expensed for Tax Purposes	(1,887)	(3,460)	(1,573)	
16	Capitalized Interest	(4,766)	-	4,766	
17	Amortization/Re-amortization of Contributions in Aid of Construction	1,990	(2,545)	(4,535)	Schedule 55
18	CCA Rate Change of 2007 & 2008	-	(624)	(624)	
19	2008 Overheads Capitalized Rate Change	-	(1,455)	(1,455)	
20	Total Timing Differences	($6,388)	($5,740)	$648	x-ref Schedule 5, 30

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
Tab 13

NON-TAX DEDUCTIBLE EXPENSES (NET) AND TIMING DIFFERENCE ADJUSTMENTS | Schedule 34
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Forecast	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**ITEMS OF A PERMANENT NATURE INCREASING TAXABLE INCOME**				
2	Amortization of Deferred Charges	$5,949	(6,660)	($12,609)	Schedule 28
3	Non-tax Deductible Expenses	66	67	1	
4	Total Permanent Differences	$6,015	($6,593)	($12,608)	x-ref Schedule 6, 31
5	**TIMING DIFFERENCE ADJUSTMENTS**				
6	Depreciation	$23,798	$26,231	$2,433	Schedule 28
7	Amortization of Debt Issue Expenses	26	36	10	
8	Transmission Pipeline Inspection Costs	-	(590)	(590)	
9	Debt Issue Costs	(548)	(534)	14	
10	Capital Cost Allowance	(23,741)	(29,986)	(6,245)	Schedule 37
11	Cumulative Eligible Capital Allowance	(398)	(375)	23	
12	Taxable Capital Gain	2,859	856	(2,003)	
13	Pension & OPEB Expense Booked	2,237	2,345	109	
14	Pension & OPEB Contributions	(1,888)	(1,612)	276	
15	Overheads Capitalized Expensed for Tax Purposes	(3,460)	-	3,460	
16	Capitalized Interest	-	-	-	
17	Amortization of Contributions in Aid of Construction	(2,545)	(4,415)	(1,870)	Schedule 56
18	CCA Rate Change of 2007 & 2008	(624)	-	624	
19	2008 Overheads Capitalized Rate Change	(1,455)	-	1,455	
20	Total Timing Differences	($5,740)	($8,044)	($2,304)	x-ref Schedule 6, 31

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
Tab 13
Schedule 35

NON-TAX DEDUCTIBLE EXPENSES (NET) AND TIMING DIFFERENCE ADJUSTMENTS
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars (1)	2010 FORECAST (2)	2011 Forecast (3)	Change (4)	Reference (5)
1	**ITEMS OF A PERMANENT NATURE INCREASING TAXABLE INCOME**				
2	Amortization of Deferred Charges	($6,660)	(754)	$5,907	Schedule 29
3	Non-tax Deductible Expenses	67	68	1	
4	Total Permanent Differences	($6,593)	($686)	$5,908	x-ref Schedule 7, 32
5	**TIMING DIFFERENCE ADJUSTMENTS**				
6	Depreciation	$26,231	$30,409	4178	Schedule 29
7	Amortization of Debt Issue Expenses	36	42	6	
8	Transmission Pipeline Inspection Costs	(590)	(460)	130	
9	Debt Issue Costs	(534)	(862)	(328)	
10	Capital Cost Allowance	(29,986)	(38,743)	(8,757)	Schedule 38
11	Cumulative Eligible Capital Allowance	(375)	(352)	23	
12	Taxable Capital Gain	856	60	(797)	
13	Pension & OPEB Expense Booked	2,345	2,438	93	
14	Pension & OPEB Contributions	(1,612)	(1,661)	(49)	
15	Overheads Capitalized Expensed for Tax Purposes	-	-	-	
16	Capitalized Interest	-	-	-	
17	Amortization of Contributions in Aid of Construction	(4,415)	(4,423)	(8)	Schedule 57
18	CCA Rate Change of 2007 & 2008	-	-	-	
19	2008 Overheads Capitalized Rate Change	-	-	-	
20	Total Timing Differences	($8,044)	($13,552)	($5,509)	x-ref Schedule 7, 32

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
CAPITAL COST ALLOWANCE Schedule 36
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Class	CCA Rate %	12/31/2008 UCC Balance	Adjustments	2009 Net Additions	2009 CCA	12/31/2009 UCC Balance	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
1	1	4%	$307,018	$0	$0	($12,281)	$294,737	
2	1.3	6%	$4,728	(70)	269	(288)	4,639	
3	2	6%	$7,570	-	-	(454)	7,116	
4	3	5%	$150	-	-	(8)	142	
5	6	10%	$7	-	-	(1)	6	
6	7	15%	$15,874	235	3,752	(2,698)	17,163	
7	8	20%	$8,153	(19)	683	(1,695)	7,122	
8	9	25%	$0	-	-	-	-	
9	10	30%	$2,034	(25)	630	(697)	1,942	
10	12	100%	$520	(20)	1,988	(1,494)	994	
11	13	17%	$137	-	40	(39)	138	
12	14	5%	$350	-	-	(25)	325	
13	14	20%	($0)	-	-	-	-	
14	38	30%	$246	(3)	148	(95)	296	
15	45	45%	$235	-	-	(106)	129	
16	47	8%	$0	-	-	-	-	
17	49	8%	$5,888	89	28,207	(1,606)	32,578	
18	50	55%	$418	(58)	-	(198)	162	
19	51	6%	$26,529	1,205	13,052	(2,056)	38,730	
20		Total	$379,857	$1,334	$48,769	($23,741)	$406,219	x-ref Schedule 33

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
CAPITAL COST ALLOWANCE Schedule 37
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Class	CCA Rate %	12/31/2009 UCC Balance	Adjustments	2010 Net Additions	2010 CCA	12/31/2010 UCC Balance	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
1	1	4%	$294,737	$0	$0	($11,789)	$282,948	
2	1.3	6%	4,639	1	210	(285)	4,565	
3	2	6%	7,116	-	-	(427)	6,689	
4	3	5%	142	1	-	(7)	136	
5	6	10%	6	-	-	(1)	5	
6	7	15%	17,163	1	1,984	(2,723)	16,425	
7	8	20%	7,122	-	893	(1,514)	6,501	
8	10	25%	-	-	-	-	-	
9	12	30%	1,942	(1)	630	(677)	1,894	
10	13	100%	994	-	1,500	(1,744)	750	
11	14	17%	138	-	30	(28)	140	
12	17	5%	325	-	-	(25)	300	
13	38	20%	-	-	-	-	-	
14	39	30%	296	-	186	(117)	365	
15	45	45%	129	-	-	(58)	71	
16	47	8%	-	-	79,145	(4,957)	74,188	
17	49	8%	32,578	-	3,639	(2,752)	33,465	
18	50	55%	162	-	-	(89)	73	
19	51	6%	38,730	-	15,649	(2,793)	51,586	
20		Total	$406,219	$2	$103,866	($29,986)	$480,101	x-ref Schedule 34

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
CAPITAL COST ALLOWANCE Schedule 38
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Class	CCA Rate %	12/31/2010 UCC Balance	Adjustments	2011 Net Additions	2011 CCA	12/31/2011 UCC Balance	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
1	1	4%	$282,948	$0	$0	($11,318)	$271,630	
2	1.3	6%	4,565	-	4,980	(423)	9,122	
3	2	6%	6,689	-	-	(401)	6,288	
4	3	5%	136	-	-	(7)	129	
5	6	10%	5	1	-	(1)	5	
6	7	15%	16,425	(1)	10,449	(3,247)	23,626	
7	8	20%	6,501	-	888	(1,389)	6,000	
8	10	25%	-	-	-	-	-	
9	12	30%	1,894	1	560	(652)	1,803	
10	13	100%	750	-	1,500	(1,500)	750	
11	14	17%	140	(1)	40	(31)	148	
12	17	5%	300	-	-	(25)	275	
13	38	20%	-	-	-	-	-	
14	39	30%	365	-	154	(133)	386	
15	45	45%	71	-	-	(32)	39	
16	47	8%	74,188	1	97,626	(12,599)	159,216	
17	49	8%	33,465	-	16,565	(3,340)	46,690	
18	50	55%	73	-	-	(40)	33	
19	51	6%	51,586	(1)	17,007	(3,605)	64,987	
20		Total	$480,101	$0	$149,769	($38,743)	$591,127	x-ref Schedule 35

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
UTILITY RATE BASE Schedule 39
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Approved Rates	2009 Adjustments	2009 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$737,301	$733,157	$0	$733,157	($4,144)	Schedule 44
2	Adjustment*		208,237	0	208,237	208,237	
3	Gas Plant in Service, Ending	785,862	1,012,319	0	1,012,319	226,458	Schedule 44
4	Accumulated Depreciation Beginning - Plant	(178,559)	(178,029)	0	(178,029)	530	Schedule 50
5	Adjustment*		(45,847)	0	(45,847)	(45,847)	
6	Accumulated Depreciation Ending - Plant	(196,352)	(245,154)	0	(245,154)	(48,802)	Schedule 50
					0		
7	CIAC, Beginning	(60,835)	(60,835)	0	(60,835)	(0)	Schedule 55
8	Adjustment*		(208,237)	0	(208,237)	(208,237)	
9	CIAC, Ending	(53,475)	(278,861)	0	(278,861)	(225,386)	Schedule 55
10	Accumulated Amortization Beginning - CIAC	1,990	1,990	0	1,990	(0)	Schedule 55
11	Adjustment*		45,847	0	45,847	45,847	
12	Accumulated Amortization Ending - CIAC	0	50,380	0	50,380	50,380	Schedule 55
13	Net Plant in Service, Mid-Year	$517,966	$517,483	$0	$517,483	($482)	
14	Adjustment to 13-Month Average	817	6,489	0	6,489	5,672	
15	Allocated Common Plant to TGW, Mid-Year	(104)	(104)	0	(104)	0	
16	Work in Progress, No AFUDC	1,812	3,652	0	3,652	1,840	
17	Unamortized Deferred Charges	6,246	3,689	0	3,689	(2,557)	Schedule 58
18	Cash Working Capital	(2,100)	(2,589)	(407)	(2,996)	(895)	Schedule 61
19	Other Working Capital (incl. Construction Advances)	14,889	11,575	0	11,575	(3,313)	Schedule 61
20	Future Income Taxes Regulatory Asset		58,802	0	58,802	58,802	Schedule 67
21	Future Income Taxes Liability		(58,802)	0	(58,802)	(58,802)	Schedule 67
22	**Utility Rate Base**	$539,525	$540,195	($407)	$539,788	$264	x-ref Schedule 68

*Adjustment to remove CIAC from Gas Plant in Service, and Accumulated Amortization of CIAC from Accumulated Depreciaton

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
UTILITY RATE BASE Schedule 40
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Approved Rates	2010 Adjustments	2010 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$733,157	$1,012,319	$0	$1,012,319	$279,162	Schedule 46
2	Adjustment	208,237					
3	Gas Plant in Service, Ending	1,012,319	1,036,234	0	1,036,234	23,915	
4	Accumulated Depreciation Beginning - Plant	(178,029)	(245,154)	0	(245,154)	(67,125)	Schedule 52
5	Adjustment*	(45,847)	(1,379)		(1,379)		
6	Accumulated Depreciation Ending - Plant	(245,154)	(270,987)	0	(270,987)	(25,833)	
7	CIAC, Beginning	(60,835)	(278,861)	0	(278,861)	(218,026)	Schedule 56
8	Adjustment	(208,237)					
9	CIAC, Ending	(278,861)	(275,728)	0	(275,728)	3,133	
10	Accumulated Amortization Beginning - CIAC	1,990	50,380	0	50,380	48,390	Schedule 56
11	Adjustment	45,847					
12	Accumulated Amortization Ending - CIAC	50,380	54,795	0	54,795	4,415	
13	Net Plant in Service, Mid-Year	$517,483	$540,809	$0	$540,809	$24,016	
14	Adjustment to 13-Month Average	6,489	0	0	0	(6,489)	
15	Allocated Common Plant to TGW, Mid-Year	(104)	0	0	0	104	
16	Work in Progress, No AFUDC	3,652	3,608	0	3,608	(44)	
17	Unamortized Deferred Charges	3,689	495	0	495	(3,194)	Schedule 59
18	Cash Working Capital	(2,996)	318	(750)	(432)	2,563	Schedule 62
19	Other Working Capital (incl. Construction Advances)	11,575	9,533	0	9,533	(2,043)	Schedule 62
20	Future Income Taxes Regulatory Asset	58,802	60,101	0	60,101	1,298	Schedule 67
21	Future Income Taxes Liability	(58,802)	(60,101)	0	(60,101)	(1,298)	Schedule 67
22	**Utility Rate Base**	$539,788	$554,763	($750)	$554,013	$14,914	x-ref Schedule 69

*Adjustment relates to transfer of accumulated loss on General Plant to IFRS Transitional Adjustments deferral account

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
Tab 13
Schedule 41

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Approved Rates	2011 Adjustments	2011 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$1,012,319	$1,036,234	$0	$1,036,234	$23,915	Schedule 48
2	Adjustment	0					
3	Gas Plant in Service, Ending	1,036,234	1,274,815	0	1,274,815	238,581	
4	Accumulated Depreciation Beginning - Plant	(245,154)	(270,987)	0	(270,987)	(25,833)	Schedule 54
5	Adjustment	(1,379)					
6	Accumulated Depreciation Ending - Plant	(270,987)	(299,264)	0	(299,264)	(28,277)	
7	CIAC, Beginning	(278,861)	(275,728)	0	(275,728)	3,133	Schedule 57
8	Adjustment	0					
9	CIAC, Ending	(275,728)	(276,176)	0	(276,176)	(448)	
10	Accumulated Amortization Beginning - CIAC	50,380	54,795	0	54,795	4,415	Schedule 57
11	Adjustment	0					
12	Accumulated Amortization Ending - CIAC	54,795	59,218	0	59,218	4,423	
13	Net Plant in Service, Mid-Year	$540,809	$651,454	$0	$651,454	$109,955	
14	Adjustment to 13-Month Average	0	56,712	0	56,712	56,712	
15	Allocated Common Plant to TGW, Mid-Year	0	0	0	0	0	
16	Work in Progress, No AFUDC	3,608	3,608	0	3,608	0	
17	Unamortized Deferred Charges	495	4,908	0	4,908	4,413	Schedule 60
18	Cash Working Capital	(432)	516	(381)	135	567	Schedule 63
19	Other Working Capital (incl. Construction Advances)	9,533	12,178	0	12,178	2,645	Schedule 63
20	Future Income Taxes Regulatory Asset	60,101	63,889	0	63,889	3,788	Schedule 67
21	Future Income Taxes Liability	(60,101)	(63,889)	0	(63,889)	(3,788)	Schedule 67
22	**Utility Rate Base**	$554,013	$729,375	($381)	$728,994	$174,292	x-ref Schedule 70

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
Schedule 42

CAPITAL EXPENDITURES AND PLANT ADDITIONS
FOR THE YEARS ENDING DECEMBER 31, 2009 - 2011
($000)

Line No.	Particulars	Projected 2009	Forecast 2010	Forecast 2011
	(1)	(3)	(4)	(5)
1	**CAPITAL EXPENDITURES**			
2	Regular Capital Expenditures	$24,036	$21,669	$25,827
3	Special Projects - CPCN's			
4	Squamish to Whistler Natural Gas Pipeline	$ 5,386	$ -	$ -
5	Mt. Hayes LNG Facility	62,986	57,216	26,709
6	CIS CCE	840	5,580	6,490
7	Garbaly	-	5,200	3,300
8	Total CPCN's	$ 69,212	$ 67,996	$ 36,499
9	TOTAL CAPITAL EXPENDITURES	$ 93,247	$ 89,665	$ 62,326
10	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**			
11	Regular Capital			
12	Base Capital Expenditures	$ 24,036	$ 21,669	$ 25,827
13	Add - Opening WIP	6,305	6,305	6,305
14	Less - Closing WIP	(6,305)	(6,305)	(6,305)
15	Add - AFUDC	68	52	69
16	Add - Overhead Capitalized	5,033	4,372	4,567
		Schedule 44	Schedule 46	Schedule 48
17	TOTAL REGULAR CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	$ 29,136	$ 26,093	$ 30,463
18	Special Projects - CPCN's			
19	CPCN Expenditures	$ 69,212	$ 67,996	$ 36,499
20	Add - Opening WIP	84,881	115,759	192,949
21	Less - Closing WIP	(115,759)	(192,949)	(22,868)
22	Add - AFUDC	5,633	9,194	4,068
23	TOTAL CPCN ADDITIONS TO GAS PLANT IN SERVICE	$ 43,966	$ 0	$ 210,648
		Schedule 44	Schedule 46	Schedule 48

TERASEN GAS (VANCOUVER ISLAND) INC.

Nov. 5 2009 NSP Agreement

Section C
Tab 13
Schedule 43

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	Balance 12/31/2008	Opening Adjustments	CPCN'S	2009 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2009
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	401-00 Franchise and Consents	$190	$0	$0	$0	$0	$0	$190
3	402-00 Utility Plant Acquisition Adjustment	-	-	-	-	-	-	-
4	402-00 Other Intangible Plant	1,194	-	-	-	-	-	1,194
5	441-00 Land Rights	-	-	-	-	-	-	-
6	461-00 Land Rights - Transmission	-	6,802	-	75	-	-	6,877
7	471-00 Land Rights - Distribution	-	1,830	-	85	-	-	1,915
8	461-00 Land Rights - Whistler	-	-	-	-	-	-	-
9	402-00 Application Software - 8 year life	-	14,947	-	2,000	(47)	-	16,900
10	402-00 Application Software - 5 year life	-	1,654	-	-	-	-	1,654
11	TOTAL INTANGIBLE PLANT	1,384	25,233	-	2,160	(47)	-	28,730
12	**MANUFACTURED GAS / LOCAL STORAGE**							
13	430 Manufact'd Gas - Land	-	-	-	-	-	-	-
14	432 Manufact'd Gas - Struct. & Improvements	-	-	-	-	-	-	-
15	433 Manufact'd Gas - Equipment	-	-	-	-	-	-	-
16	434 Manufact'd Gas - Gas Holders	-	-	-	-	-	-	-
17	436 Manufact'd Gas - Compressor Equipment	-	-	-	-	-	-	-
18	437 Manufact'd Gas - Measuring & Regulating Equipment	-	-	-	-	-	-	-
19	440/441 Land in Fee Simple and Land Rights	-	-	-	-	-	-	-
20	442 Structures & Improvements	-	-	-	-	-	-	-
21	443 Gas Holders - Storage	-	-	-	-	-	-	-
22	446 Compressor Equipment	-	-	-	-	-	-	-
23	447 Measuring & Regulating Equipment	-	-	-	-	-	-	-
24	448 Purification Equipment	-	-	-	-	-	-	-
25	- Piping	-	-	-	-	-	-	-
26	- Pre-treatment	-	-	-	-	-	-	-
27	- Liquefaction Equipment	-	-	-	-	-	-	-
28	- Send out Equipment	-	-	-	-	-	-	-
29	- Sub-station and Electric	-	-	-	-	-	-	-
30	- Control Room	-	-	-	-	-	-	-
31	449 Local Storage Equipment	-	-	-	-	-	-	-
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	-	-	-	-	-	-	-
33	**TRANSMISSION PLANT**							
34	460-00 Land in Fee Simple	2,842	-	-	-	-	-	2,842
35	461-00 Land Rights	6,802	(6,802)	-	-	-	-	-
36	462-00 Compressor Structures	10,446	819	-	-	-	-	11,265
37	463-00 Measuring Structures	6,449	1,257	-	-	-	-	7,706
38	464-00 Other Structures & Improvements	130	-	-	-	-	-	130
39	465-00 Mains	223,423	99,338	43,669	4,018	-	-	370,448
40	465-00 Mains - Inspection	-	-	-	-	-	-	-
41	466-00 Compressor Equipment	50,252	6,947	-	4,589	-	-	61,788
42	466-00 Compressor Equipment - Compressor Overhaul	-	-	-	-	-	-	-
43	466-00 Compressor Equipment - Gas Turbine Overhaul	-	-	-	-	-	-	-
44	467-00 Measuring & Regulating Equipment	10,735	3,698	297	127	-	-	14,857
45	467-10 Telemetering	-	-	-	-	-	-	-
46	468-00 Communication Structures & Equipment	2,376	890	-	-	-	-	3,266
47	469-00 Other Transmission Equipment	-	-	-	-	-	-	-
48	TOTAL TRANSMISSION PLANT	313,455	106,147	43,966	8,734	-	-	472,302

TERASEN GAS (VANCOUVER ISLAND) INC.

Nov. 5 2009 NSP Agreement

Section C
Tab 13
Schedule 44

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	Balance 12/31/2008	Opening Adjustments	CPCN'S	2009 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2009	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	**DISTRIBUTION PLANT**								
2	470-00 Land in Fee Simple	$799	$0	$0	$83	$0	$0	$882	
3	471-00 Land Rights	$1,830	($1,830)	$0	$0	$0	$0	$0	
4	472-00 Structures & Improvements	1,465	666	-	-	-	-	2,131	
5	473-00 Services	131,548	26,273	-	8,330	(417)	-	165,734	
6	474-00 House Regulators & Meter Installations	16,970	2,809	-	994	(50)	-	20,723	
7	475-00 Mains	208,940	61,534	-	5,773	(289)	-	275,958	
8	476-00 Compressor Equipment	-	-	-	-	-	-	-	
9	477-00 Measuring & Regulating Equipment	5,000	2,146	-	513	-	-	7,659	
10	477-00 Telemetering	-	-	-	-	-	-	-	
12	478-00 Meters	11,122	1,861	-	788	(39)	-	13,732	
13	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	
14	TOTAL DISTRIBUTION PLANT	377,674	93,459	-	16,481	(795)	-	486,819	
15	**GENERAL PLANT & EQUIPMENT**								
16	480-00 Land in Fee Simple	1,065	-	-	-	-	-	1,065	
17	481-00 Land Rights	-	-	-	-	-	-	-	
18	482-00 Structures & Improvements	-	-	-	-	-	-	-	
19	- Frame Buildings	4,343	-	-	260	-	-	4,603	
20	- Masonry Buildings	-	-	-	-	-	-	-	
21	- Leasehold Improvement	1,344	-	-	40	(964)	-	420	
22	483-00 Office Furniture and Equipment	-	-	-	-	-	-	-	
23	- Furniture & Equipment	2,424	-	-	97	-	-	2,521	
24	- Computer Hardware	2,265	-	-	-	-	-	2,265	
25	- Computer Software (Infrastructure)	15,907	(15,907)	-	-	-	-	-	
26	- Computer Software (Non-Infrastructure)	906	(695)	-	-	-	-	211	
27	484-00 Transportation Equipment	4,593	-	-	630	-	-	5,223	
28	485-00 Heavy Work Equipment	786	-	-	148	-	-	934	
29	486-00 Small Tools & Equipment	5,888	-	-	506	-	-	6,394	
30	487-00 Equipment on Customer's Premises	-	-	-	-	-	-	-	
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	
32	488-00 Communications Equipment	-	-	-	-	-	-	-	
33	- Telephone	1,123	-	-	80	(371)	-	832	
34	- Radio	-	-	-	-	-	-	-	
35	489-00 Other General Equipment	-	-	-	-	-	-	-	
36	TOTAL GENERAL PLANT	40,644	(16,602)	-	1,761	(1,335)	-	24,468	
37	**UNCLASSIFIED PLANT**								
38	499 Plant Suspense	-	-	-	-	-	-	-	
39	TOTAL UNCLASSIFIED PLANT	-	-	-	-	-	-	-	
40	TOTAL	$733,157	$208,237	$43,966	$29,136	($2,177)	$0	$1,012,319	x-ref Schedules 8, 39, 42

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C Tab 13 Schedule 45

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Balance 12/31/2009	CPCN'S	2010 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**INTANGIBLE PLANT**						
2	401-00 Franchise and Consents	$190	$0	$0	$0	$0	$190
3	402-00 Utility Plant Acquisition Adjustment	-	-	-	-	-	-
4	402-00 Other Intangible Plant	1,194	-	-	-	-	1,194
5	441-00 Land Rights	-	-	-	-	-	-
6	461-00 Land Rights - Transmission	6,877	-	77	-	-	6,954
7	471-00 Land Rights - Distribution	1,915	-	-	-	-	1,915
8	461-00 Land Rights - Whistler	-	-	-	-	-	-
9	402-00 Application Software - 8 year life	16,900	-	1,509	(91)	-	18,318
10	402-00 Application Software - 5 year life	1,654	-	-	-	-	1,654
11	TOTAL INTANGIBLE PLANT	28,730	-	1,586	(91)	-	30,225
12	**MANUFACTURED GAS / LOCAL STORAGE**						
13	430 Manufact'd Gas - Land	-	-	-	-	-	-
14	432 Manufact'd Gas - Struct. & Improvements	-	-	-	-	-	-
15	433 Manufact'd Gas - Equipment	-	-	-	-	-	-
16	434 Manufact'd Gas - Gas Holders	-	-	-	-	-	-
17	436 Manufact'd Gas - Compressor Equipment	-	-	-	-	-	-
18	437 Manufact'd Gas - Measuring & Regulating Equipment	-	-	-	-	-	-
19	440/441 Land in Fee Simple and Land Rights	-	-	-	-	-	-
20	442 Structures & Improvements	-	-	-	-	-	-
21	443 Gas Holders - Storage	-	-	-	-	-	-
22	446 Compressor Equipment	-	-	-	-	-	-
23	447 Measuring & Regulating Equipment	-	-	-	-	-	-
24	448 Purification Equipment	-	-	-	-	-	-
25	- Piping	-	-	-	-	-	-
26	- Pre-treatment	-	-	-	-	-	-
27	- Liquefaction Equipment	-	-	-	-	-	-
28	- Send out Equipment	-	-	-	-	-	-
29	- Sub-station and Electric	-	-	-	-	-	-
30	- Control Room	-	-	-	-	-	-
31	449 Local Storage Equipment	-	-	-	-	-	-
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	-	-	-	-	-	-
33	**TRANSMISSION PLANT**						
34	460-00 Land in Fee Simple	2,842	-	-	-	-	2,842
35	461-00 Land Rights	-	-	-	-	-	-
36	462-00 Compressor Structures	11,265	-	-	-	-	11,265
37	463-00 Measuring Structures	7,706	-	-	-	-	7,706
38	464-00 Other Structures & Improvements	130	-	-	-	-	130
39	465-00 Mains	370,448	-	3,527	-	(1,630)	372,345
40	465-00 Mains - Inspection	-	-	744	-	1,630	2,374
41	466-00 Compressor Equipment	61,788	-	731	-	(3,882)	58,637
42	466-00 Compressor Equipment - Compressor Overhaul	-	-	-	-	933	933
43	466-00 Compressor Equipment - Gas Turbine Overhaul	-	-	1,261	-	2,949	4,210
44	467-00 Measuring & Regulating Equipment	14,857	-	126	-	-	14,983
45	467-10 Telemetering	-	-	-	-	-	-
46	468-00 Communication Structures & Equipment	3,266	-	-	-	-	3,266
47	469-00 Other Transmission Equipment	-	-	-	-	-	-
48	TOTAL TRANSMISSION PLANT	472,302	-	6,389	-	-	478,691

TERASEN GAS (VANCOUVER ISLAND) INC.

Nov. 5 2009 NSP Agreement

Section C
Tab 13
Schedule 46

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Balance 12/31/2009	CPCN'S	2010 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2010	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
1	**DISTRIBUTION PLANT**							
2	470-00 Land in Fee Simple	$882	$0	$0	$0	$0	$882	
3	471-00 Land Rights	-	-	-	-	-	-	
4	472-00 Structures & Improvements	2,131	-	-	-	-	2,131	
5	473-00 Services	165,734	-	8,168	(408)	-	173,494	
6	474-00 House Regulators & Meter Installations	20,723	-	1,275	(64)	-	21,934	
7	475-00 Mains	275,958	-	5,247	(262)	-	280,943	
8	476-00 Compressor Equipment	-	-	-	-	-	-	
9	477-00 Measuring & Regulating Equipment	7,659	-	504	-	-	8,163	
10	477-00 Telemetering	-	-	-	-	-	-	
12	478-00 Meters	13,732	-	1,016	(51)	-	14,697	
13	479-00 Other Distribution Equipment	-	-	-	-	-	-	
14	TOTAL DISTRIBUTION PLANT	486,819	-	16,210	(785)	-	502,244	
15	**GENERAL PLANT & EQUIPMENT**							
16	480-00 Land in Fee Simple	1,065	-	-	-	-	1,065	
17	481-00 Land Rights	-	-	-	-	-	-	
18	482-00 Structures & Improvements	-	-	-	-	-	-	
19	- Frame Buildings	4,603	-	167	-	-	4,770	
20	- Masonry Buildings	-	-	-	-	-	-	
21	- Leasehold Improvement	420	-	30	-	-	450	
22	483-00 Office Furniture and Equipment	-	-	-	-	-	-	
23	- Furniture & Equipment	2,521	-	94	(897)	-	1,718	
24	- Computer Hardware	2,265	-	-	(192)	-	2,073	
25	- Computer Software (Infrastructure)	-	-	-	-	-	-	
26	- Computer Software (Non-Infrastructure)	211	-	-	-	-	211	
27	484-00 Transportation Equipment	5,223	-	630	(52)	-	5,801	
28	485-00 Heavy Work Equipment	934	-	186	-	-	1,120	
29	486-00 Small Tools & Equipment	6,394	-	516	-	-	6,910	
30	487-00 Equipment on Customer's Premises	-	-	-	-	-	-	
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	
32	488-00 Communications Equipment	-	-	-	-	-	-	
33	- Telephone	832	-	80	(160)	-	752	
34	- Radio	-	-	204	-	-	204	
35	489-00 Other General Equipment	-	-	-	-	-	-	
36	TOTAL GENERAL PLANT	24,468	-	1,907	(1,301)	-	25,074	
37	**UNCLASSIFIED PLANT**							
38	499 Plant Suspense	-	-	-	-	-	-	
39	TOTAL UNCLASSIFIED PLANT	-	-	-	-	-	-	
40	TOTAL	$1,012,319	$0	$26,092	($2,177)	$0	$1,036,234	x-ref Schedules 9, 40, 42

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
Schedule 47

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	CPCN'S	2011 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**INTANGIBLE PLANT**						
2	401-00 Franchise and Consents	$190	$0	$0	$0	$0	$190
3	402-00 Utility Plant Acquisition Adjustment	-	-	-	-	-	-
4	402-00 Other Intangible Plant	1,194	-	-	-	-	1,194
5	441-00 Land Rights	-	140	-	-	-	140
6	461-00 Land Rights - Transmission	6,954	-	78	-	-	7,032
7	471-00 Land Rights - Distribution	1,915	-	-	-	-	1,915
8	461-00 Land Rights - Whistler	-	-	-	-	-	-
9	402-00 Application Software - 8 year life	18,318	-	1,509	(340)	-	19,487
10	402-00 Application Software - 5 year life	1,654	-	-	-	-	1,654
11	TOTAL INTANGIBLE PLANT	30,225	140	1,587	(340)	-	31,612
12	**MANUFACTURED GAS / LOCAL STORAGE**						
13	430 Manufact'd Gas - Land	-	-	-	-	-	-
14	432 Manufact'd Gas - Struct. & Improvements	-	-	-	-	-	-
15	433 Manufact'd Gas - Equipment	-	-	-	-	-	-
16	434 Manufact'd Gas - Gas Holders	-	-	-	-	-	-
17	436 Manufact'd Gas - Compressor Equipment	-	-	-	-	-	-
18	437 Manufact'd Gas - Measuring & Regulating Equipment	-	-	-	-	-	-
19	440/441 Land in Fee Simple and Land Rights	-	849	-	-	-	849
20	442 Structures & Improvements	-	24,479	-	-	-	24,479
21	443 Gas Holders - Storage	-	55,956	-	-	-	55,956
22	446 Compressor Equipment	-	-	-	-	-	-
23	447 Measuring & Regulating Equipment	-	-	-	-	-	-
24	448 Purification Equipment	-	-	-	-	-	-
25	- Piping	-	16,635	-	-	-	16,635
26	- Pre-treatment	-	7,461	-	-	-	7,461
27	- Liquefaction Equipment	-	26,113	-	-	-	26,113
28	- Send out Equipment	-	39,169	-	-	-	39,169
29	- Sub-station and Electric	-	12,564	-	-	-	12,564
30	- Control Room	-	9,326	-	-	-	9,326
31	449 Local Storage Equipment	-	13,056	-	-	-	13,056
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	-	205,608	-	-	-	205,608
33	**TRANSMISSION PLANT**						
34	460-00 Land in Fee Simple	2,842	-	-	-	-	2,842
35	461-00 Land Rights	-	-	-	-	-	-
36	462-00 Compressor Structures	11,265	-	-	-	-	11,265
37	463-00 Measuring Structures	7,706	-	-	-	-	7,706
38	464-00 Other Structures & Improvements	130	-	-	-	-	130
39	465-00 Mains	372,345	-	6,022	-	-	378,367
40	465-00 Mains - Inspection	2,374	-	560	-	-	2,934
41	466-00 Compressor Equipment	58,637	453	956	-	-	60,046
42	466-00 Compressor Equipment - Compressor Overhaul	933	-	731	-	-	1,664
43	466-00 Compressor Equipment - Gas Turbine Overhaul	4,210	-	1,218	-	-	5,428
44	467-00 Measuring & Regulating Equipment	14,983	4,447	122	-	-	19,552
45	467-10 Telemetering	-	-	-	-	-	-
46	468-00 Communication Structures & Equipment	3,266	-	-	-	-	3,266
47	469-00 Other Transmission Equipment	-	-	-	-	-	-
48	TOTAL TRANSMISSION PLANT	478,691	4,900	9,609	-	-	493,200

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
Schedule 48

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	CPCN'S	2011 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**DISTRIBUTION PLANT**						
2	470-00 Land in Fee Simple	$882	$0	$0	$0	$0	$882
3	471-00 Land Rights	-	-	-	-	-	-
4	472-00 Structures & Improvements	2,131	-	-	-	-	2,131
5	473-00 Services	173,494	-	8,517	(426)	-	181,585
6	474-00 House Regulators & Meter Installations	21,934	-	1,259	(63)	-	23,130
7	475-00 Mains	280,943	-	6,422	(321)	-	287,044
8	476-00 Compressor Equipment	-	-	-	-	-	-
9	477-00 Measuring & Regulating Equipment	8,163	-	390	-	-	8,553
10	477-00 Telemetering	-	-	-	-	-	-
12	478-00 Meters	14,697	-	1,039	(52)	-	15,684
13	479-00 Other Distribution Equipment	-	-	-	-	-	-
14	TOTAL DISTRIBUTION PLANT	502,244	-	17,627	(862)	-	519,009
15	**GENERAL PLANT & EQUIPMENT**						
16	480-00 Land in Fee Simple	1,065	-	-	-	-	1,065
17	481-00 Land Rights	-	-	-	-	-	-
18	482-00 Structures & Improvements	-	-	-	-	-	-
19	- Frame Buildings	4,770	-	-	-	-	4,770
20	- Masonry Buildings	-	-	-	-	-	-
21	- Leasehold Improvement	450	-	40	-	-	490
22	483-00 Office Furniture and Equipment	-	-	-	-	-	-
23	- Furniture & Equipment	1,718	-	101	(729)	-	1,090
24	- Computer Hardware	2,073	-	-	(175)	-	1,898
25	- Computer Software (Infrastructure)	-	-	-	-	-	-
26	- Computer Software (Non-Infrastructure)	211	-	-	-	-	211
27	484-00 Transportation Equipment	5,801	-	560	(162)	-	6,199
28	485-00 Heavy Work Equipment	1,120	-	154	(32)	-	1,242
29	486-00 Small Tools & Equipment	6,910	-	457	(210)	-	7,157
30	487-00 Equipment on Customer's Premises	-	-	-	-	-	-
31	- VRA Compressor Installation Costs	-	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-	-
33	- Telephone	752	-	80	(22)	-	810
34	- Radio	204	-	250	-	-	454
35	489-00 Other General Equipment	-	-	-	-	-	-
36	TOTAL GENERAL PLANT	25,074	-	1,642	(1,330)	-	25,386
37	**UNCLASSIFIED PLANT**						
38	499 Plant Suspense	-	-	-	-	-	-
39	TOTAL UNCLASSIFIED PLANT	-	-	-	-	-	-
40	TOTAL	$1,036,234	$210,648	$30,465	($2,532)	$0	$1,274,815 x-ref Schedules 10, 40, 42

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Account	Jan.1 GPIS for Depreciation	Annual Depreciation Rate %	Provision 2009 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2008	Opening Adjustment	12/31/2009
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**INTANGIBLE PLANT**										
2	401-00 Franchise and Consents	190	3.04%	$6	$0	$0	$0	$0	$56	$0	$62
3	402-00 Utility Plant Acquisition Adjustment	-	0.00%	-	-	-	-	-	-	-	-
4	402-00 Other Intangible Plant	1,194	6.21%	74	-	-	-	-	490	-	564
4	441-00 Land Rights	-	0.00%	-	-	-	-	-	-	-	-
5	461-00 Land Rights - Transmission	6,802	1.33%	90	-	-	-	-	-	1,100	1,190
6	471-00 Land Rights - Distribution	1,830	1.36%	25	-	-	-	-	-	236	261
8	461-00 Land Rights - Whistler	-	0.00%	-	-	-	-	-	-	-	-
9	402-00 Application Software - 8 year life	14,947	12.50%	1,868	-	(47)	-	-	-	4,449	6,270
10	402-00 Application Software - 5 year life	1,654	20.00%	331	-	-	-	-	-	213	544
11	TOTAL INTANGIBLE PLANT	26,617		2,394	-	(47)	-	-	546	5,998	8,891
12	**MANUFACTURED GAS / LOCAL STORAGE**										
13	430 Manufact'd Gas - Land	-	0.00%	-	-	-	-	-	-	-	-
14	432 Manufact'd Gas - Struct. & Improvements	-	0.00%	-	-	-	-	-	-	-	-
15	433 Manufact'd Gas - Equipment	-	0.00%	-	-	-	-	-	-	-	-
16	434 Manufact'd Gas - Gas Holders	-	0.00%	-	-	-	-	-	-	-	-
17	436 Manufact'd Gas - Compressor Equipment	-	0.00%	-	-	-	-	-	-	-	-
18	437 Manufact'd Gas - Measuring & Regulating Equipment	-	0.00%	-	-	-	-	-	-	-	-
19	440/441 Land in Fee Simple and Land Rights	-	0.00%	-	-	-	-	-	-	-	-
20	442 Structures & Improvements	-	0.00%	-	-	-	-	-	-	-	-
21	443 Gas Holders - Storage	-	0.00%	-	-	-	-	-	-	-	-
22	446 Compressor Equipment	-	0.00%	-	-	-	-	-	-	-	-
23	447 Measuring & Regulating Equipment	-	0.00%	-	-	-	-	-	-	-	-
24	448 Purification Equipment	-	0.00%	-	-	-	-	-	-	-	-
25	- Piping	-	0.00%	-	-	-	-	-	-	-	-
26	- Pre-treatment	-	0.00%	-	-	-	-	-	-	-	-
27	- Liquefaction Equipment	-	0.00%	-	-	-	-	-	-	-	-
28	- Send out Equipment	-	0.00%	-	-	-	-	-	-	-	-
29	- Sub-station and Electric	-	0.00%	-	-	-	-	-	-	-	-
30	- Control Room	-	0.00%	-	-	-	-	-	-	-	-
31	449 Local Storage Equipment	-	0.00%	-	-	-	-	-	-	-	-
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	-		-	-	-	-	-	-	-	-
33	**TRANSMISSION PLANT**										
34	460-00 Land in Fee Simple	2,842	0.00%	-	-	-	-	-	-	-	-
35	461-00 Land Rights	-	0.00%	-	-	-	-	-	1,100	(1,100)	-
36	462-00 Compressor Structures	11,265	3.77%	425	-	-	-	-	2,727	283	3,435
37	463-00 Measuring Structures	7,706	3.75%	289	-	-	-	-	2,058	234	2,581
38	464-00 Other Structures & Improvements	130	3.00%	4	-	-	-	-	13	-	17
39	465-00 Mains	322,761	1.97%	6,358	-	-	-	-	59,317	21,490	87,165
40	465-00 Mains - Inspection	-	0.00%	-	-	-	-	-	-	-	-
41	466-00 Compressor Equipment	57,199	3.50%	2,002	-	-	-	-	10,897	2,293	15,192
42	Compressor Equipment - Compressor Overhaul	-	0.00%	-	-	-	-	-	-	-	-
43	Compressor Equipment - Gas Turbine Overhaul	-	0.00%	-	-	-	-	-	-	-	-
44	467-00 Measuring & Regulating Equipment	14,433	3.11%	449	-	-	-	-	1,947	1,134	3,530
45	467-10 Telemetering	-	0.00%	-	-	-	-	-	-	-	-
46	468-00 Communication Structures & Equipment	3,266	6.45%	211	-	-	-	-	1,006	523	1,740
47	469-00 Other Transmission Equipment	-	0.00%	-	-	-	-	-	-	-	-
48	TOTAL TRANSMISSION PLANT	419,602		9,738	-	-	-	-	79,065	24,857	113,660

TERASEN GAS (VANCOUVER ISLAND) INC.

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Account	CPCN + Jan.1 GPIS for Depreciation	Annual Depreciation Rate %	Provision 2009 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2008	Opening Adjustment	12/31/2009
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**DISTRIBUTION PLANT**										
2	470 Land	$799	0.00%	$0	$0	$0	$0	$0	$0	$0	$0
3	481-00 Land Rights	-	0.00%	-	-	-	-	-	236	(236)	-
4	-Frame Buildings	2,131	2.31%	49	-	-	-	-	634	189	872
5	473-00 Services	157,821	2.62%	4,135	-	(417)	(268)	-	24,334	6,109	33,893
6	474-00 House Regulator & Meter Installation	19,779	2.88%	570	-	(50)	(25)	-	4,154	807	5,456
7	475-00 Mains	270,474	1.89%	5,112	-	(289)	(50)	-	51,015	11,538	67,326
8	-All Other	-	0.00%	-	-	-	-	-	-	-	-
9	477-00 Measuring & Regulating	7,146	3.66%	262	-	-	-	-	1,881	680	2,823
10	477-10 Telemetering	-	0.00%	-	-	-	-	-	-	-	-
11	478 Meters	12,983	3.08%	400	-	(39)	-	-	3,030	567	3,958
12	479 Other Distribution Equipment	-	0.00%	-	-	-	-	-	-	-	-
13	TOTAL DISTRIBUTION PLANT	471,133		10,528	-	(795)	(343)	-	85,284	19,654	114,328
14	**GENERAL PLANT & EQUIPMENT**										
15	480-00 Land in Fee Simple	1,065	0.00%	-	-	-	-	-	-	-	-
16	481-00 Land Rights	-	0.00%	-	-	-	-	-	-	-	-
17	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-	-	-	-
18	- Frame Buildings	4,343	2.44%	106	-	-	-	-	926	-	1,032
19	- Masonry Buildings	-	0.00%	-	-	-	-	-	-	-	-
20	- Leasehold Improvement	1,344	6.07%	82	-	(964)	-	-	(194)	-	(1,076)
21	483-00 Office Furniture and Equipment	-	0.00%	-	-	-	-	-	-	-	-
22	- Furniture & Equipment	2,424	5.00%	121	-	-	-	-	1,742	-	1,863
23	- Computer Hardware	2,265	5.99%	136	-	-	-	-	782	-	918
24	- Computer Software (Infrastructure)	-	12.50%	-	-	-	-	-	4,661	(4,661)	-
25	- Computer Software (Non-Infrastructure)	211	20.00%	42	-	-	-	-	24	(1)	65
26	484-00 Transportation Equipment	4,593	5.03%	231	-	-	-	-	1,413	-	1,644
27	485-00 Heavy Work Equipment	786	5.34%	42	-	-	-	-	136	-	178
28	486-00 Small Tools & Equipment	5,888	4.85%	286	-	-	-	-	2,862	-	3,148
29	487-00 Equipment on Customer's Premises	-	0.00%	-	-	-	-	-	-	-	-
30	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-	-	-	-
31	488-00 Communications Equipment	-	0.00%	-	-	-	-	-	-	-	-
32	- Telephone	1,123	8.21%	92	-	(371)	-	-	782	-	503
33	- Radio	-	0.00%	-	-	-	-	-	-	-	-
34	489-00 Other General Equipment	-	0.00%	-	-	-	-	-	-	-	-
35	TOTAL GENERAL PLANT	24,042		1,138	-	(1,335)	-	-	13,134	(4,662)	8,275
36	**UNCLASSIFIED PLANT**										
37	499 Plant Suspense	-	0.00%	-	-	-	-	-	-	-	-
38	TOTAL UNCLASSIFIED PLANT	-		-	-	-	-	-	-	-	-
39	TOTAL	941,394		23,798	-	(2,177)	(343)	-	178,029	45,847	245,154
										x-ref Schedules 8, 39	
40	Less: Vehicle Depreciation allocated to Capital Projects			-							
41	Net Depreciation Expense			$23,798	x-ref Schedule 27					100%	

TERASEN GAS (VANCOUVER ISLAND) INC.

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Account	13 mo. Avg 2010 GPIS Balance for Depreciation	Annual Depreciation Rate %	Provision 2010 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2009	Opening Adjustment	12/31/2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(10)
1	**INTANGIBLE PLANT**										
2	401-00 Franchise and Consents	190	3.13%	$6	$0	$0	$0	$0	$62	$0	68
3	402-00 Utility Plant Acquisition Adjustment	-	0.00%	-	-	-	-	-	-	-	-
4	402-00 Other Intangible Plant	1,194	2.30%	27	-	-	-	-	564	-	591
4	441-00 Land Rights	-	0.00%	-	-	-	-	-	-	-	-
5	461-00 Land Rights - Transmission	6,916	0.00%	-	-	-	-	-	1,190	-	1,190
6	471-00 Land Rights - Distribution	1,915	0.00%	-	-	-	-	-	261	-	261
8	461-00 Land Rights - Whistler	-	0.00%	-	-	-	-	-	-	-	-
9	402-00 Application Software - 8 year life	17,609	12.50%	2,201	-	(91)	-	-	6,270	-	8,380
10	402-00 Application Software - 5 year life	1,654	20.00%	331	-	-	-	-	544	-	875
11	TOTAL INTANGIBLE PLANT	29,478		2,565	-	(91)	-	-	8,891	-	11,365
12	**MANUFACTURED GAS / LOCAL STORAGE**										
13	430 Manufact'd Gas - Land	-	0.00%	-	-	-	-	-	-	-	-
14	432 Manufact'd Gas - Struct. & Improvements	-	0.00%	-	-	-	-	-	-	-	-
15	433 Manufact'd Gas - Equipment	-	0.00%	-	-	-	-	-	-	-	-
16	434 Manufact'd Gas - Gas Holders	-	0.00%	-	-	-	-	-	-	-	-
17	436 Manufact'd Gas - Compressor Equipment	-	0.00%	-	-	-	-	-	-	-	-
18	437 Manufact'd Gas - Measuring & Regulating Equipment	-	0.00%	-	-	-	-	-	-	-	-
19	440/441 Land in Fee Simple and Land Rights	-	0.00%	-	-	-	-	-	-	-	-
20	442 Structures & Improvements	-	0.00%	-	-	-	-	-	-	-	-
21	443 Gas Holders - Storage	-	0.00%	-	-	-	-	-	-	-	-
22	446 Compressor Equipment	-	0.00%	-	-	-	-	-	-	-	-
23	447 Measuring & Regulating Equipment	-	0.00%	-	-	-	-	-	-	-	-
24	448 Purification Equipment	-	0.00%	-	-	-	-	-	-	-	-
25	- Piping	-	0.00%	-	-	-	-	-	-	-	-
26	- Pre-treatment	-	0.00%	-	-	-	-	-	-	-	-
27	- Liquefaction Equipment	-	0.00%	-	-	-	-	-	-	-	-
28	- Send out Equipment	-	0.00%	-	-	-	-	-	-	-	-
29	- Sub-station and Electric	-	0.00%	-	-	-	-	-	-	-	-
30	- Control Room	-	0.00%	-	-	-	-	-	-	-	-
31	449 Local Storage Equipment	-	0.00%	-	-	-	-	-	-	-	-
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	-		-	-	-	-	-	-	-	-
33	**TRANSMISSION PLANT**										
34	460-00 Land in Fee Simple	2,842	0.00%	-	-	-	-	-	-	-	-
35	461-00 Land Rights	-	0.00%	-	-	-	-	-	-	-	-
36	462-00 Compressor Structures	11,265	3.72%	419	-	-	-	-	3,435	-	3,854
37	463-00 Measuring Structures	7,706	2.87%	221	-	-	-	-	2,581	-	2,802
38	464-00 Other Structures & Improvements	130	2.87%	4	-	-	-	-	17	-	21
39	465-00 Mains	371,397	1.73%	6,425	-	-	-	-	87,165	-	93,591
40	465-00 Mains - Inspection	1,187	0.00%	316	-	-	-	-	-	-	316
41	466-00 Compressor Equipment	60,213	3.19%	1,921	-	-	-	-	15,192	-	17,113
42	Compressor Equipment - Compressor Overhaul	467	0.00%	613	-	-	-	-	-	-	613
43	Compressor Equipment - Gas Turbine Overhaul	2,105	0.00%	1,095	-	-	-	-	-	-	1,095
44	467-00 Measuring & Regulating Equipment	14,920	5.59%	834	-	-	-	-	3,530	-	4,364
45	467-10 Telemetering	-	5.59%	-	-	-	-	-	-	-	-
46	468-00 Communication Structures & Equipment	3,266	10.07%	329	-	-	-	-	1,740	-	2,069
47	469-00 Other Transmission Equipment	-	0.00%	-	-	-	-	-	-	-	-
48	TOTAL TRANSMISSION PLANT	475,498		12,178	-	-	-	-	113,660	-	125,838

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

				Provision					Accumulated		
Line No.	Account	13 mo. Avg 2010 GPIS Balance for Depreciation	Annual Depreciation Rate %	2010 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	12/31/2009	Opening Adjustment	12/31/2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(10)
1	**DISTRIBUTION PLANT**										
2	470 Land	$882	0.00%	$0	$0	$0	$0	$0	$0	$0	-
3	481-00 Land Rights	-	0.00%	-	-	-	-	-	-	-	-
4	-Frame Buildings	2,131	3.21%	68	-	-	-	-	872	-	940
5	473-00 Services	169,614	1.91%	3,240	-	(408)	-	-	33,893	-	36,725
6	474-00 House Regulator & Meter Installation	21,329	3.45%	736	-	(64)	-	-	5,456	-	6,128
7	475-00 Mains	278,451	1.62%	4,511	-	(262)	-	-	67,326	-	71,575
8	-All Other	-	0.00%	-	-	-	-	-	-	-	-
9	477-00 Measuring & Regulating	7,911	4.60%	364	-	-	-	-	2,823	-	3,187
10	477-10 Telemetering	-	0.00%	-	-	-	-	-	-	-	-
11	478 Meters	14,215	4.37%	621	-	(51)	-	-	3,958	-	4,528
12	479 Other Distribution Equipment	-	0.00%	-	-	-	-	-	-	-	-
13		494,533		9,540	-	(785)	-	-	114,328	-	123,083
14	**GENERAL PLANT & EQUIPMENT**										
15	480-00 Land in Fee Simple	1,065	0.00%	-	-	-	-	-	-	-	-
16	481-00 Land Rights	-	0.00%	-	-	-	-	-	-	-	-
17	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-	-	-	-
18	- Frame Buildings	4,687	4.36%	204	-	-	-	-	1,032	(381)	855
19	- Masonry Buildings	-	0.00%	-	-	-	-	-	-	-	-
20	- Leasehold Improvement	435	17.86%	78	-	-	-	-	(1,076)	1,224	226
21	483-00 Office Furniture and Equipment	-	0.00%	-	-	-	-	-	-	-	-
22	- Furniture & Equipment	2,120	6.55%	139	-	(897)	-	-	1,863	427	1,532
23	- Computer Hardware	2,169	20.00%	434	-	(192)	-	-	918	385	1,545
24	- Computer Software (Infrastructure)	-	12.50%	-	-	-	-	-	-	-	-
25	- Computer Software (Non-Infrastructure)	211	20.00%	42	-	-	-	-	65	-	107
26	484-00 Transportation Equipment	5,512	17.88%	986	-	(52)	-	-	1,644	(362)	2,216
27	485-00 Heavy Work Equipment	1,027	7.03%	72	-	-	-	-	178	70	320
28	486-00 Small Tools & Equipment	6,652	5.00%	333	-	-	-	-	3,148	16	3,497
29	487-00 Equipment on Customer's Premises	-	0.00%	-	-	-	-	-	-	-	-
30	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-	-	-	-
31	488-00 Communications Equipment	-	0.00%	-	-	-	-	-	-	-	-
32	- Telephone	792	6.67%	53	-	(160)	-	-	503	-	396
33	- Radio	102	6.67%	7	-	-	-	-	-	-	7
34	489-00 Other General Equipment	-	0.00%	-	-	-	-	-	-	-	-
35	TOTAL GENERAL PLANT	24,772		2,348	-	(1,301)	-	-	8,275	1,379	10,701
0											
36	**UNCLASSIFIED PLANT**										
37	499 Plant Suspense	-	0.00%	-	-	-	-	-	-	-	-
38	TOTAL UNCLASSIFIED PLANT	-		-	-	-	-	-	-	-	-
39	TOTAL	1,024,281		26,631	-	(2,177)	-	-	245,154	1,379	270,987
									x-ref Schedules 9, 40		
40	Less: Vehicle Depreciation allocated to Capital Projects			(400)							
41	Net Depreciation Expense			$26,231	x-ref Schedule 28						

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
Schedule 53

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account	13 mo. Avg 2011 GPIS Balance for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Provision Proceeds on Disposal	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	401-00 Franchise and Consents	190	3.13%	$6	$0	$0	$0	$0	$68	$74
3	402-00 Utility Plant Acquisition Adjustment	-	0.00%	-	-	-	-	-	-	-
4	402-00 Other Intangible Plant	1,194	2.30%	27	-	-	-	-	591	618
4	441-00 Land Rights	70	0.00%	-	-	-	-	-	-	-
5	461-00 Land Rights - Transmission	6,993	0.00%	-	-	-	-	-	1,190	1,190
6	471-00 Land Rights - Distribution	1,915	0.00%	-	-	-	-	-	261	261
8	461-00 Land Rights - Whistler	-	0.00%	-	-	-	-	-	-	-
9	402-00 Application Software - 8 year life	18,903	12.50%	2,363	-	(340)	-	-	8,380	10,403
10	402-00 Application Software - 5 year life	1,654	20.00%	331	-	-	-	-	875	1,206
11	TOTAL INTANGIBLE PLANT	30,919		2,727	-	(340)	-	-	11,365	13,752
12	**MANUFACTURED GAS / LOCAL STORAGE**									
13	430 Manufact'd Gas - Land	-	0.00%	-	-	-	-	-	-	-
14	432 Manufact'd Gas - Struct. & Improvements	-	0.00%	-	-	-	-	-	-	-
15	433 Manufact'd Gas - Equipment	-	0.00%	-	-	-	-	-	-	-
16	434 Manufact'd Gas - Gas Holders	-	0.00%	-	-	-	-	-	-	-
17	436 Manufact'd Gas - Compressor Equipment	-	0.00%	-	-	-	-	-	-	-
18	437 Manufact'd Gas - Measuring & Regulating Equipment	-	0.00%	-	-	-	-	-	-	-
19	440/441 Land in Fee Simple and Land Rights	659	0.00%	-	-	-	-	-	-	-
20	442 Structures & Improvements	18,992	6.00%	734	-	-	-	-	-	734
21	443 Gas Holders - Storage	43,412	2.51%	701	-	-	-	-	-	701
22	446 Compressor Equipment	-	0.00%	-	-	-	-	-	-	-
23	447 Measuring & Regulating Equipment	-	0.00%	-	-	-	-	-	-	-
24	448 Purification Equipment	-	0.00%	-	-	-	-	-	-	-
25	- Piping	12,906	3.75%	312	-	-	-	-	-	312
26	- Pre-treatment	5,789	6.00%	224	-	-	-	-	-	224
27	- Liquefaction Equipment	20,260	3.75%	490	-	-	-	-	-	490
28	- Send out Equipment	30,389	3.75%	734	-	-	-	-	-	734
29	- Sub-station and Electric	9,747	3.75%	236	-	-	-	-	-	236
30	- Control Room	7,235	10.01%	467	-	-	-	-	-	467
31	449 Local Storage Equipment	10,129	4.29%	280	-	-	-	-	-	280
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	159,519		4,177	-	-	-	-	-	4,177
33	**TRANSMISSION PLANT**									
34	460-00 Land in Fee Simple	2,842	0.00%	-	-	-	-	-	-	-
35	461-00 Land Rights	-	0.00%	-	-	-	-	-	-	-
36	462-00 Compressor Structures	11,265	3.72%	419	-	-	-	-	3,854	4,273
37	463-00 Measuring Structures	7,706	2.87%	221	-	-	-	-	2,802	3,023
38	464-00 Other Structures & Improvements	130	2.87%	4	-	-	-	-	21	25
39	465-00 Mains	375,356	1.73%	6,494	-	-	-	-	93,591	100,085
40	465-00 Mains - Inspection	2,654	9.70%	257	-	-	-	-	316	573
41	466-00 Compressor Equipment	59,342	3.20%	1,899	-	-	-	-	17,113	19,012
42	Compressor Equipment - Compressor Overhaul	1,299	12.03%	156	-	-	-	-	613	769
43	Compressor Equipment - Gas Turbine Overhaul	4,819	16.91%	815	-	-	-	-	1,095	1,910
44	467-00 Measuring & Regulating Equipment	17,268	5.95%	1,027	-	-	-	-	4,364	5,391
45	467-10 Telemetering	-	0.00%	-	-	-	-	-	-	-
46	468-00 Communication Structures & Equipment	3,266	10.07%	329	-	-	-	-	2,069	2,398
47	469-00 Other Transmission Equipment	-	0.00%	-	-	-	-	-	-	-
48	TOTAL TRANSMISSION PLANT	485,947		11,621	-	-	-	-	125,838	137,459

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C Tab 13 Schedule 54

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account	13 mo. Avg 2011 GPIS Balance for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Provision Proceeds on Disposal	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**DISTRIBUTION PLANT**									
2	470 Land	$882	0.00%	$0	$0	$0	$0	$0	$0	$0
3	481-00 Land Rights	-	0.00%	-	-	-	-	-	-	-
4	-Frame Buildings	2,131	3.21%	68	-	-	-	-	940	1,008
5	473-00 Services	177,540	1.91%	3,391	-	(426)	-	-	36,725	39,690
6	474-00 House Regulator & Meter Installation	22,532	3.45%	777	-	(63)	-	-	6,128	6,842
7	475-00 Mains	283,994	1.62%	4,601	-	(321)	-	-	71,575	75,855
8	-All Other	-	0.00%	-	-	-	-	-	-	-
9	477-00 Measuring & Regulating	8,358	4.60%	384	-	-	-	-	3,187	3,571
10	477-10 Telemetering	-	0.00%	-	-	-	-	-	-	-
11	478 Meters	15,191	4.37%	664	-	(52)	-	-	4,528	5,140
12	479 Other Distribution Equipment	-	0.00%	-	-	-	-	-	-	-
13		510,628		9,885	-	(862)	-	-	123,083	132,106
14	**GENERAL PLANT & EQUIPMENT**									
15	480-00 Land in Fee Simple	1,065	0.00%	-	-	-	-	-	-	-
16	481-00 Land Rights	-	0.00%	-	-	-	-	-	-	-
17	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-	-	-
18	- Frame Buildings	4,770	4.36%	208	-	-	-	-	855	1,063
19	- Masonry Buildings	-	0.00%	-	-	-	-	-	-	-
20	- Leasehold Improvement	470	16.53%	78	-	-	-	-	226	304
21	483-00 Office Furniture and Equipment	-	0.00%	-	-	-	-	-	-	-
22	- Furniture & Equipment	1,404	6.48%	91	-	(729)	-	-	1,532	894
23	- Computer Hardware	1,986	20.00%	397	-	(175)	-	-	1,545	1,767
24	- Computer Software (Infrastructure)	-	12.50%	-	-	-	-	-	-	-
25	- Computer Software (Non-Infrastructure)	211	20.00%	42	-	-	-	-	107	149
26	484-00 Transportation Equipment	6,000	17.88%	1,073	-	(162)	-	-	2,216	3,127
27	485-00 Heavy Work Equipment	1,181	7.09%	84	-	(32)	-	-	320	372
28	486-00 Small Tools & Equipment	7,034	5.00%	352	-	(210)	-	-	3,497	3,639
29	487-00 Equipment on Customer's Premises	-	0.00%	-	-	-	-	-	-	-
30	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-	-	-
31	488-00 Communications Equipment	-	0.00%	-	-	-	-	-	-	-
32	- Telephone	781	6.67%	52	-	(22)	-	-	396	426
33	- Radio	329	6.67%	22	-	-	-	-	7	29
34	489-00 Other General Equipment	-	0.00%	-	-	-	-	-	-	-
35	TOTAL GENERAL PLANT	25,231		2,399	-	(1,330)	-	-	10,701	11,770
36	**UNCLASSIFIED PLANT**									
37	499 Plant Suspense	-	0.00%	-	-	-	-	-	-	-
38	TOTAL UNCLASSIFIED PLANT	-		-	-	-	-	-	-	-
39	TOTAL	1,212,244		30,809	-	(2,532)	-	-	270,987	299,264
40	Less: Vehicle Depreciation allocated to Capital Projects			(400)						
41	Net Depreciation Expense			$30,409						

x-ref Schedules 10, 41

Net Depreciation Expense: x-ref Schedule 29

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	Balance 12/31/2008	CPCN / Jan.1 Bal Adjustment	2009 Additions / Reamortization	2009 Additions	2009 Retirements / Repayment	Balance 12/31/2009	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
1	**CIAC**							
2								
3	Distribution Contributions	$0	$95,288	$0	$892	$0	$96,180	
4								
5	Transmission Contributions	-	112,949	-	-	-	112,949	
6								
7	Others	-	-	-	-	-	-	
8								
9	TGW Contribution for Whistler Pipeline	-	17,034	-	-	-	17,034	
10	Government Loans Contribution	60,835	-	-	-	(8,137)	52,698	
11								
12	TOTAL Contributions	60,835	225,271	-	892	(8,137)	278,861	x-ref Schedule 8, 39
13								
14								
15								
16	**Amortization**							
17								
18	Distribution Contributions	-	(19,525)	(2,084)	-	-	(21,609)	
19								
20	Transmission Contributions	-	(26,320)	(2,451)	-	-	(28,771)	
21								
22	Others	-	-	-	-	-	-	
23								
24	TGW Contribution for Whistler Pipeline	-	-	-	-	-	-	
25	Government Loans Contribution	(1,990)	-	1,990	-	-	-	
26								
27	TOTAL Amortization	(1,990)	(45,845)	(2,545)	-	-	(50,380)	x-ref Schedule 8, 39
28								
29	**NET CONTRIBUTIONS**	$58,845	179,426	($2,545)	$892	($8,137)	$228,481	

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Balance 12/31/2009	CPCN / Jan.1 Bal Adjustment	2010 Additions / Reamortization	2010 Additions	2010 Retirements / Repayment	Balance 12/31/2010	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
1	**CIAC**							
2								
3	Distribution Contributions	$96,180	$0	$0	$442	$0	$96,622	
4								
5	Transmission Contributions	112,949	-	-	-	-	112,949	
6								
7	Others	-	-	-	-	-	-	
8								
9	TGW Contribution for Whistler Pipeline	17,034	-	-	-	-	17,034	
10	Government Loans Contribution	52,698	-	-	-	(3,575)	49,123	
11								
12	TOTAL Contributions	278,861	-	-	442	(3,575)	275,728	x-ref Schedule 9, 40
13								
14								
15								
16	**Amortization**							
17								
18	Distribution Contributions	(21,609)	-	(1,817)	-	-	(23,426)	
19								
20	Transmission Contributions	(28,771)	-	(2,303)	-	-	(31,074)	
21								
22	Others	-	-	-	-	-	-	
23								
24	TGW Contribution for Whistler Pipeline	-	-	(295)	-	-	(295)	
25	Government Loans Contribution	-	-	-	-	-	-	
26								
27	TOTAL Amortization	(50,380)	-	(4,415)	-	-	(54,795)	x-ref Schedule 9, 40
28								
29	**NET CONTRIBUTIONS**	$228,481	$0	($4,415)	$442	($3,575)	$220,933	

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	CPCN / Jan.1 Bal Adjustment	2011 Additions / Reamortization	2011 Additions	2011 Retirements / Repayment	Balance 12/31/2011	
	(1)	(2)	(3)	(4)	(5)	(5)	(6)	
1	**CIAC**							
2								
3	Distribution Contributions	$96,622	$0	$0	$448	$0	$97,070	
4								
5	Transmission Contributions	112,949	-	-	-	-	112,949	
6								
7	Others	-	-	-	-	-	-	
8								
9	TGW Contribution for Whistler Pipeline	17,034	-	-	-	-	17,034	
10	Government Loans Contribution	49,123	-	-	-	-	49,123	
11								
12	TOTAL Contributions	275,728	-	-	448	-	276,176	x-ref Schedule 10, 41
13								
14								
15								
16	**Amortization**							
17								
18	Distribution Contributions	(23,426)	-	(1,825)	-	-	(25,251)	
19								
20	Transmission Contributions	(31,074)	-	(2,303)	-	-	(33,377)	
21								
22	Others	-	-	-	-	-	-	
23								
24	TGW Contribution for Whistler Pipeline	(295)	-	(295)	-	-	(590)	
25	Government Loans Contribution	-	-	-	-	-	-	
26								
27	TOTAL Amortization	(54,795)	-	(4,423)	-	-	(59,218)	x-ref Schedule 10, 41
28								
29	**NET CONTRIBUTIONS**	$220,933	$0	($4,423)	$448	$0	$216,958	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	Balance 12/31/2008	Gross Additions	Less- Taxes*	Net Additions	Amortization Expense	Balance 12/31/2009	Mid-Year Average 2009	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	Gas Cost Variance Account (GCVA)	$4,162	($5,781)	$1,734	($4,047)	($4,162)	($4,047)	$58	x-ref Schedules 2, 14, 27
2	Energy Policy Related								
3	Energy Efficiency & Conservation (EEC)	-	1,379	(414)	965	-	965	483	
4	NGV Conversion Grants	-	-	-	-	-	-	-	
5	Non-Controllable Items								
6	Insurance Variance	-	51	(15)	36	(36)	(0)	-	
7	Pension Expense	-	299	-	299	(299)	-	-	
8	Olympic Security Costs	-	84	(25)	59	-	59	29	
9	IFRS Conversion Costs	11	56	(17)	39	-	50	31	
10	Cost of Current Applications								
11	2010-2011 Revenue Requirement Application	40	118	(35)	82	-	122	81	
12	2009 ROE & Cost of Capital Application	-	70	(21)	49	-	49	25	
13	CCE CPCN Application	-	30	(9)	21	-	21	11	
14	2009 Rate Design Application	-	69	(21)	48	-	48	24	
15	Other								
16	PCEC Start Up Costs	1,184	-	-	-	(44)	1,140	1,162	
17	IFRS Transitional Adjustments	-	-	-	-	-	-	-	
18	Pension & OPEB funding	-	-	-	-	-	-	-	
19	Residual Deferred Charges								
20	Compressor Fired Hours	(1,288)	(770)	231	(539)	-	(1,827)	(1,557)	
21	LNG	826	-	-	-	(415)	411	619	
22	VIGP	15	-	-	-	(7)	7	11	
23	OSC - Compliance Certification Costs	-	12	(4)	9	(9)	0	-	
24	Financing Costs	2,429	-	-	-	(240)	2,189	2,309	
25	Preliminary Survey & Investigation costs	36	0	-	0	-	36	36	
26	BC Capital Tax Assessment & Appeal Cost	737	-	-	-	(737)	-	369	
30	Total Deferred Charges for Rate Base	$8,152	($4,383)	$1,405	($2,979)	($5,949)	($775)	$3,689	x-ref Schedules 8, 39
31	Non-Rate Base Deferral Accounts								
32	RDDA	7,149	(10,211)	3,062	(7,149)	-	(0)	3,575	
33	2009 Revenue Surplus	-	(4,231)	1,269	(2,962)	-	(2,962)	(1,481)	
34	Rate Stabilization Deferral Account	-	-	-	-	-	-	-	
35	Interest Accumulated on RSDA	-	-	-	-	-	-	-	
36	Financing Costs	-	-	-	-	-	-	-	
37	Total Deferred Charges for Non-Rate Base	$7,149	($14,443)	$4,331	($10,112)	$0	($2,962)	$2,093	

38 Notes:
39 *Taxes= 30% x Gross Addition

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Forecast Balance 12/31/2009	Opening Adjustment	Gross Additions	Less- Taxes*	Net Additions	Amortization Expense	Balance 12/31/2010	Mid-Year Average 2010	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
1	Gas Cost Variance Account (GCVA)	($4,047)		$0	$0	$0	$4,047	$0	($2,023)	x-ref Schedules 3, 14, 28
2	Energy Policy Related									
3	Energy Efficiency & Conservation (EEC)	965		5,204	(1,483)	3,721	(97)	4,590	2,778	
4	NGV Conversion Grants	-		100	-	100	-	100	50	
5	Non-Controllable Items									
6	Insurance Variance	(0)		-	-	-	-	(0)	-	
7	Pension Expense	-		-	-	-	-	-	-	
8	Olympic Security Costs	59		298	(85)	213	-	272	165	
9	IFRS Conversion Costs	50		34	(10)	25	-	75	63	
10	Cost of Current Applications									
11	2010-2011 Revenue Requirement Application	122		-	-	-	(61)	61	92	
12	2009 ROE & Cost of Capital Application	49		-	-	-	(10)	39	44	
13	CCE CPCN Application	21		-	-	-	(4)	17	19	
14	2009 Rate Design Application	48		-	-	-	(24)	24	36	
15	Other									
16	PCEC Start Up Costs	1,140		-	-	-	(44)	1,096	1,118	
17	IFRS Transitional Adjustments	-	1,379	-	-	1,379	-	1,379	1,379	
18	Pension & OPEB funding	-		(5,076)	-	(5,076)	-	(5,076)	(2,538)	
19	Residual Deferred Charges									
20	Compressor Fired Hours	(1,827)		-	-	-	1,827	(0)	(913)	
21	LNG	411		-	-	-	(411)	(0)	206	
22	VIGP	7		-	-	-	(7)	-	4	
23	OSC - Compliance Certification Costs	0		-	-	-	-	0	-	
24	Financing Costs	2,189	(2,189)	-	-	(2,189)	-	-	-	
25	Preliminary Survey & Investigation costs	36		-	-	-	(36)	-	18	
26	BC Capital Tax Assessment & Appeal Cost	-		-	-	-	-	-	-	
30	Total Deferred Charges for Rate Base	($775)	($811)	$560	($1,578)	($1,828)	$5,179	$2,576	$495	x-ref Schedules 9, 40
31	Non-Rate Base Deferral Accounts									
32	RDDA	-		-	-	-	-	-	-	
33	2009 Revenue Surplus	(2,962)		-	-	-	1,481	(1,481)	(2,222)	x-ref Schedule 28
34	Rate Stabilization Deferral Account	-		(44,473)	12,140	(32,333)	-	(32,333)	(16,167)	
35	Interest Accumulated on RSDA	-		(404)	115	(289)	-	(289)	(145)	
36	Financing Costs	-	2,189	1,000	-	1,000	(250)	2,940	2,564	
37	Total Deferred Charges for Non-Rate Base	($2,962)	$2,189	($43,878)	$12,255	($31,622)	$1,231	($31,164)	($15,969)	

38 Notes:
39 *Taxes = 28.5% x Gross Addition

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Forecast Balance 12/31/2010	Gross Additions	Less-Taxes*	Net Additions	Amortization Expense	Balance 12/31/2011	Mid-Year Average 2011	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	Gas Cost Variance Account (GCVA)	0	0	0	0	0	0	0	x-ref Schedules 4, 14, 29
2	Energy Policy Related								
3	Energy Efficiency & Conservation (EEC)	4,590	5,683	(1,506)	4,177	(469)	8,298	6,444	
4	NGV Conversion Grants	100	100	0	100	0	200	150	
5	Non-Controllable Items								
6	Insurance Variance	(0)	0	0	0	0	(0)	0	
7	Pension Expense	0	0	0	0	0	0	0	
8	Olympic Security Costs	272	0	0	0	(91)	181	226	
9	IFRS Conversion Costs	75	18	(5)	14	(25)	63	69	
10	Cost of Current Applications								
11	2010-2011 Revenue Requirement Application	61	0	0	0	(61)	0	31	
12	2009 ROE & Cost of Capital Application	39	0	0	0	(10)	29	34	
13	CCE CPCN Application	17	0	0	0	(4)	13	15	
14	2009 Rate Design Application	24	0	0	0	(24)	(0)	12	
15	Other								
16	PCEC Start Up Costs	1,096	0	0	0	(44)	1,052	1,074	
17	IFRS Transitional Adjustments	1,379	11,790	0	11,790	0	13,169	7,274	
18	Pension & OPEB funding	(5,076)	(10,689)	0	(10,689)	0	(15,765)	(10,421)	
19	Residual Deferred Charges								
20	Compressor Fired Hours	(0)	0	0	0	0	(0)	0	
21	LNG	(0)	0	0	0	0	(0)	0	
22	VIGP	0	0	0	0	0	0	0	
23	OSC - Compliance Certification Costs	0	0	0	0	0	0	0	
24	Financing Costs	0	0	0	0	0	0	0	
25	Preliminary Survey & Investigation costs	0	0	0	0	0	0	0	
26	BC Capital Tax Assessment & Appeal Cost	0	0	0	0	0	0	0	
30	Total Deferred Charges for Rate Base	$2,576	$6,902	($1,511)	$5,392	($727)	$7,240	$4,908	x-ref Schedules 10, 41
31	Non-Rate Base Deferral Accounts								
32	RDDA	0	0	0	0	0	0	0	
33	2009 Revenue Surplus	(1,481)	0	0	0	1,481	0	(741)	x-ref Schedule 29
34	Rate Stabilization Deferral Account	(32,333)	(26,471)	6,517	(18,087)	0	(50,420)	(41,377)	
35	Interest Accumulated on RSDA	(289)	(1,972)	523	(1,450)	0	(1,739)	(1,014)	
36	Financing Costs	2,940	1,000	0	1,000	(50)	3,889	3,414	
37	Total Deferred Charges for Non-Rate Base	($31,049)	($27,443)	$7,040	($18,536)	$1,431	($48,270)	($39,717)	

38 Notes:
39 *Taxes = 26.5% x Gross Addition

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Approved Rates	2009 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$5,293	$4,738	$4,331	($962)	Schedule 64
4	Customer Deposits	(2,215)	(2,191)	(2,191)	24	
6	Less - Funds Available:					
7	Reserve for Bad Debts		0	-	-	
8	Withholdings From Employees	(5,178)	(5,136)	(5,136)	42	
9	Subtotal	(2,100)	(2,589)	(2,996)	(895)	x-ref Schedules 8, 39
10	**Other Working Capital Items**					
11	Refundable Contribution	(289)	(290)	(290)	(1)	
12	Gas in Storage	14,943	11,865	11,865	(3,079)	
13	Inventory - Materials & Supplies	234	0	-	(234)	
14	Other Working Capital Items		0	0	0	
15	Subtotal	14,889	11,575	11,575	(3,313)	x-ref Schedules 8, 39
16	Total	$12,788	$8,986	$8,579	($4,209)	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Approved Rates	2010 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$4,331	$2,345	$1,595	($2,736)	Schedule 64
4	Customer Deposits	(2,191)	0	-	2,191	
6	Less - Funds Available:					
7	Reserve for Bad Debts	0	(1,008)	(1,008)	(1,008)	
8	Withholdings From Employees	(5,136)	(1,019)	(1,019)	4,117	
9	Subtotal	(2,996)	318	(432)	2,563	x-ref Schedules 9, 40
10	**Other Working Capital Items**					
11	Refundable Contribution	(290)	(290)	(290)	(0)	
12	Gas in Storage	11,865	9,822	9,822	(2,043)	
13	Inventory - Materials & Supplies	0	0	-	-	
14	Other Working Capital Items	0	0	0	0	
15	Subtotal	11,575	9,533	9,533	(2,043)	x-ref Schedules 9, 40
16	Total	$8,579	$9,850	$9,100	$521	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Approved Rates	2011 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$1,595	$2,291	$1,910	$315	Schedule 64
4	Customer Deposits	0	0	-	0	
6	Less - Funds Available:					
7	Reserve for Bad Debts	(1,008)	(1,045)	(1,045)	(37)	
8	Withholdings From Employees	(1,019)	(730)	(730)	289	
9	Subtotal	(432)	516	135	567	x-ref Schedules 10, 41
10	**Other Working Capital Items**					
11	Refundable Contribution	(290)	(290)	(290)	0	
12	Gas in Storage	9,822	12,467	12,467	2,645	
13	Inventory - Materials & Supplies	0	0	0	0	
14	Other Working Capital Items	0	0	0	0	
15	Subtotal	9,533	12,178	12,178	2,645	x-ref Schedules 10, 41
16	Total	$9,100	$12,694	$12,313	$3,213	

CASH WORKING CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

		2009			2010			2011			
Line No.	Particulars	Days	Expenses	Cash Working Capital	Days	Expenses	Cash Working Capital	Days	Expenses	Cash Working Capital	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**CASH WORKING CAPITAL**										
2	Revenue Lag Days	43.8			39.7			39.8			Schedule 65
3	Expense Lead Days	33.5			34.7			35.2			Schedule 66
4	Net Lead/(Lag) Days	10.3	$167,909	$4,738	5.0	171,216	$2,345	4.6	$181,768	$2,291	
5	**CASH WORKING CAPITAL, COST OF SERVICE RATES**										
6	Revenue Lag Days	43.8			39.9			39.9			Schedule 65
7	Expense Lead Days	34.1			36.2			35.9			Schedule 66
8	Net Lead/(Lag) Days	9.7	$162,980	$4,331	3.7	$157,325	$1,595	4.0	$174,258	$1,910	Schedule 62
9	**CASH WORKING CAPITAL CHANGE**			($407)			($750)			($381)	

\# Cash working capital = Col. 2 x Col. 3 / 365 days

CASH WORKING CAPITAL
LEAD TIME FROM DATE OF PAYMENT TO RECEIPT OF CASH
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

		2009			2010			2011			
Line No.	Particulars	Revenue At Approved Rates	Lag Days Service to Collection	Dollar Days	Revenue At Approved Rates	Lag Days Service to Collection	Dollar Days	Revenue At Approved Rates	Lag Days Service to Collection	Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**REVENUE**										
2	Gas Sales and Transportation Service Revenue										
3	Residential and Commercial	$176,878	43.8	$7,747,242	$176,746	38.7	$6,842,760	$179,702	38.7	$6,957,438	Schedules 18, 19, 20
4	Industrial (ILF & HLF)	2,624	43.8	114,918	2,699	38.4	103,658	2,699	38.4	103,658	
5	NGV Fuel - Stations	0	0.0	0	0	0.0	0	0	0.0	0	
6	T-Service	22,194	43.8	972,108	20,669	38.4	793,684	20,501	38.4	787,197	
7	Total Gas Sales	201,696	43.8	8,834,268	200,114	38.7	7,740,102	202,902	38.7	7,848,293	
8	Other Revenues										
9	Late Payment Charges	368	43.8	16,110	340	38.9	13,226	345	38.9	13,436	Schedule 22
10	Returned Cheque Charges	4	43.8	158	5	38.9	191	5	38.9	195	
11	Connection Charges	519	43.8	22,741	370	38.9	14,385	380	38.9	14,790	
12	Other Utility Income	2	43.8	105	2	38.9	93	732	38.9	28,514	
13	Royalty Revenue - For CWC Reasons	28,095	43.8	1,281,118	35,832	45.6	1,633,921	40,091	45.6	1,828,168	
14	LNG Mitigation	0	0.0	0	0	0.0	0	9,020	38.9	350,878	
15	Total Revenue	$230,684	43.8	$10,154,500	$236,663	39.7	$9,401,918	$253,475	39.8	$10,084,274	
16	**REVENUE, COST OF SERVICE RATES**										
17	Gas Sales and Transportation Service Revenue										
18	Residential and Commercial	$162,549	43.8	$7,119,633	$134,490	38.7	$5,205,395	$155,269	38.7	$6,010,520	Schedules 18, 19, 20
19	Industrial (ILF & HLF)	2,510	43.8	109,925	2,350	38.4	90,256	2,529	38.4	97,129	
20	NGV Fuel - Stations	0	0.0	0	0	0.0	0	0	0.0	0	
21	T-Service	22,194	43.8	972,108	20,669	38.4	793,684	20,501	38.4	787,197	
22	Total Gas Sales	187,253	43.8	8,201,666	157,509	38.7	6,089,335	178,299	38.7	6,894,846	
23	Other Revenues										
24	Late Payment Charges	368	43.8	16,110	340	38.9	13,226	345	38.9	13,436	Schedule 22
25	Returned Cheque Charges	4	43.8	158	5	38.9	191	5	38.9	195	
26	Connection Charges	519	43.8	22,741	370	38.9	14,385	380	38.9	14,790	
27	Other Utility Income	2	43.8	105	2	38.9	93	2	38.9	93	
28	Royalty Revenue - For CWC Reasons	28,095	43.8	1,281,118	35,832	45.6	1,633,921	40,091	45.6	1,828,168	
29	LNG Mitigation	0	0.0	0	0	0.0	0	9,020	38.9	350,878	
30	Total Revenue	$216,241	43.8	$9,521,898	$194,058	39.9	$7,751,151	$228,142	39.9	$9,102,406	

CASH WORKING CAPITAL
LAG TIME IN PAYMENT OF EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009 Amount	2009 Lead Days Expense to Payment	2009 Dollar Days	2010 Amount	2010 Lead Days Expense to Payment	2010 Dollar Days	2011 Amount	2011 Lead Days Expense to Payment	2011 Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**EXPENSES**										
2	O&M Expenses	$27,006	22.5	$607,635	$26,858	35.8	$961,516	$28,136	35.8	$1,007,255	
3	Transportation Costs	3,977	62.7	249,358	$4,015	40.2	161,403	$4,122	40.2	165,704	
4	Gas Purchases	99,314	40.5	4,022,217	98,628	40.2	3,964,846	107,311	40.2	4,313,902	
5	Taxes Other Than Income										
6	Property Taxes	8,449	3.5	29,572	9,119	2.6	23,709	9,564	2.6	24,867	
7	Carbon Tax	7,613	33.3	253,513	10,638	29.5	313,821	13,892	29.5	409,814	
8	GST - Net	2,413	50.3	121,375	2,392	39.8	95,221	2,426	39.8	96,570	
9	PST	5,959	33.3	198,435	5,905	37.1	219,076	5,965	37.1	221,302	
#	Income Tax	13,178	10.7	141,005	13,661	15.2	207,647	10,351	15.2	157,335	
#	Total	167,909	33.5	5,623,109	171,216	34.7	5,947,239	181,767	35.2	6,396,749	
#	**EXPENSES, COST OF SERVICE RATES**										
#	O&M Expenses	$27,006	22.5	$607,635	$26,858	35.8	$961,516	$28,136	35.8	$1,007,269	
#	Transportation Costs	3,977	62.7	249,358	$4,015	40.2	161,403	$4,122	40.2	165,704	
#	Gas Purchases	99,314	40.5	4,022,217	98,628	40.2	3,964,846	107,311	40.2	4,313,902	
#	Taxes Other Than Income										
#	Property Taxes	8,449	3.5	29,572	9,119	2.6	23,709	9,564	2.6	24,866	
#	Carbon Tax	7,613	33.3	253,513	10,638	29.5	313,821	13,892	29.5	409,814	
#	GST - Net	2,241	50.3	112,718	1,884	39.8	74,995	2,133	39.8	84,885	
#	PST	5,533	33.3	184,249	4,662	37.1	172,960	5,266	37.1	195,369	
#	Income Tax	8,847	10.7	94,663	1,521	15.2	23,119	3,834	15.2	58,277	
#	Total	162,980	34.1	5,553,924	157,325	36.2	5,696,370	174,258	35.9	6,260,086	

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
Tab 13
Schedule 67

FUTURE INCOME TAX LIABILITY / ASSET
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009	2010	2011
	(1)	(2)	(3)	(4)
1	Property Plant & Equipment			
2	Net Book Value *	($710,651)	($776,930)	($813,945)
3	Less: Undepreciated Capital Cost	(529,801)	(587,921)	(610,463)
4		(180,850)	(189,009)	(203,482)
5	Weighted Average Future Tax Rate	25%	25%	25%
6		(45,153)	(47,255)	(50,836)
7				
8	Total FIT Liability- After Tax (PP&E)	(45,153)	(47,255)	(50,836)
9	Total FIT Liability- After Tax (Non-PP&E)	1,031	1,206	1,040
10	Total FIT Liability- After Tax	(44,121)	(46,048)	(49,795)
11				
12	Tax Gross Up	(14,681)	(15,351)	(16,583)
13				
14	FIT Liability/Asset - End of Year	(58,802)	(61,399)	(66,379)
15				
16	FIT Liability/Asset - Opening Balance	(58,802)	(58,802)	(61,399)
17				
18	FIT Liability/Asset - Mid Year	(58,802)	(60,101)	(63,889)
19		x-ref Schedules 8, 39	x-ref Schedules 9, 40	x-ref Schedules 10, 41
20				
21	Note: * Excludes Land			

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
RETURN ON CAPITAL | Tab 13
FOR THE YEAR ENDING DECEMBER 31, 2009 | Schedule 68
($000s)

Line No.	Particulars	Reference	-------- Capitalization --------	Amount	%	Average Embedded Cost	Cost Component	Earned Return	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	APPROVED RATES								
2	Long-Term Debt	Schedule 71		$260,940	48.300%	5.956%	2.880%	15,541	x-ref Schedule 5
3	Unfunded Debt			63,177	11.700%	1.500%	0.180%	948	x-ref Schedule 5
4	Common Equity			216,078	40.000%	13.841%	5.536%	29,907	
5	Before Sub Debt Interest	Schedule 39		$540,195	100.000%		8.596%	$46,396	
6	Sub Debt Interest							1,270	x-ref Schedule 5
7	Total						8.824%	$47,666	
8	2009 COST OF SERVICE RATES - PROJECTION								
9	Long-Term Debt			$260,940	48.340%	5.956%	2.880%	15,541	x-ref Schedule 5
10	Unfunded Debt		$63,177						
11	Adjustment, Revised Rates		(244)	62,933	11.660%	1.500%	0.170%	944	x-ref Schedule 5
12	Common Equity			215,915	40.000%	9.170%	3.670%	19,799	
13	Before Sub Debt Interest	Schedule 39		$539,788	100.000%		6.720%	$36,284	
14	Sub Debt Interest							1,270	x-ref Schedule 5
15	Total						6.957%	37,554	x-ref Schedule 2, 5, 14

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
RETURN ON CAPITAL | Tab 13
FOR THE YEAR ENDING DECEMBER 31, 2010 | Schedule 69
($000s)

Line No.	Particulars	Reference	-------- Capitalization --------	Amount	%	Average Embedded Cost	Cost Component	Earned Return	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	APPROVED RATES								
2	Long-Term Debt	Schedule 72		$289,659	52.210%	5.950%	3.110%	17,233	x-ref Schedule 6
3	Unfunded Debt			43,199	7.790%	2.500%	0.190%	1,080	x-ref Schedule 6
4	Common Equity			221,905	40.000%	22.882%	9.153%	50,776	
5	Before Sub Debt Interest	Schedule 40		$554,763	100.000%		12.453%	$69,089	
6	Sub Debt Interest							261	x-ref Schedule 6
7	Total						12.501%	$69,350	
8	2010 COST OF SERVICE RATES - FORECAST								
9	Long-Term Debt			$289,659	52.280%	5.950%	3.110%	17,233	x-ref Schedule 6
10	Unfunded Debt		$43,199						
11	Adjustment, Revised Rates		(450)	42,749	7.720%	2.500%	0.190%	1,069	x-ref Schedule 6
12	Common Equity			221,605	40.000%	9.170%	3.670%	20,321	
13	Before Sub Debt Interest	Schedule 40		$554,013	100.000%		6.970%	$38,623	
14	Sub Debt Interest							261	x-ref Schedule 6
15	Total						7.019%	$38,884	x-ref Schedule 3, 6, 14

TERASEN GAS (VANCOUVER ISLAND) INC.
RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 70

Line No.	Particulars	Reference	Capitalization Amount		%	Average Embedded Cost	Cost Component	Earned Return	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	APPROVED RATES								
2	Long-Term Debt	Schedule 73		$390,731	53.570%	6.119%	3.278%	23,909	x-ref Schedule 7
3	Unfunded Debt			46,894	6.430%	4.750%	0.305%	2,227	x-ref Schedule 7
4	Common Equity			291,750	40.000%	15.361%	6.145%	44,816	
5	Total	Schedule 41		$729,375	100.000%		9.728%	$70,953	
6	2011 COST OF SERVICE RATES - FORECAST								
7	Long-Term Debt			$390,731	53.600%	6.119%	3.280%	23,909	x-ref Schedule 7
8	Unfunded Debt		$46,894						
9	Adjustment, Revised Rates		(229)	46,665	6.400%	4.750%	0.304%	2,217	x-ref Schedule 7
10	Common Equity			291,598	40.000%	9.170%	3.668%	26,740	
11	Total	Schedule 41		$728,994	100.000%		7.252%	52,866	x-ref Schedule 4, 7, 14

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
Tab 13
Schedule 71

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
1	Long Term Debt	16-Feb-2006	15-Feb-2038	6.050%	$250,000	2,014	$247,986	6.108%	$250,000	$15,270	
2											
3											
4	PCEPA Repayment Loan	1-Jan-2008	1-Jan-2013	1.630%	13,381	-	13,381	2.473%	10,940	271	
5	Long Term (Rate Base) Debt				263,381	2,014	261,367		260,940	15,541	
6	Series 1 RDDA Sub Debt	1-Jun-2006	11-Jan-2011	7.280%				7.280%	-	631	
7	Series 2 RDDA Sub Debt	1-Jun-2002	31-Jul-2012	7.370%				7.370%	3,729	275	
8	Series 4 RDDA Sub Debt	1-Jun-2004	14-May-2009	6.820%				6.820%	-	-	
9	Series 5 RDDA Sub Debt	1-Jun-2005	6-Jul-2010	5.950%				5.950%	(0)	33	
10	Series 7 RDDA Sub Debt	1-Jun-2007	26-Jun-2012	7.370%				7.370%	3,420	331	
11	Series 8 RDDA Sub Debt	1-Jun-2003	31-Jul-2008	6.300%				6.300%	-	-	
12	RDDA Subtotal								7,149	1,270	
13								Total with Sub Debt	$268,089	$16,811	x-ref Schedule 68
14								Average Embedded Cost before Sub Debt		5.956%	

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
Tab 13
Schedule 72

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
1	Long Term Debt 1	16-Feb-2006	15-Feb-2038	6.050%	$250,000	2,014	$247,986	6.108%	250,000	$15,270	
2	Long Term Debt 2	1-Oct-2010	1-Oct-2039	6.004%	100,000	1,000	99,000	6.078%	25,205	1,532	
3											
4	PCEPA Repayment Loan	1-Jan-2008	1-Jan-2013	2.630%	15,526	-	15,526	2.984%	14,454	431	
5	Long Term (Rate Base) Debt				365,526	3,014	362,512		289,659	17,233	
6	Series 1 RDDA Sub Debt	1-Jun-2006	11-Jan-2011	7.280%				7.280%	-	-	
7	Series 2 RDDA Sub Debt	1-Jun-2002	31-Jul-2012	7.370%				7.370%	-	136	
8	Series 4 RDDA Sub Debt	1-Jun-2004	14-May-2009	6.820%				6.820%	-	-	
9	Series 5 RDDA Sub Debt	1-Jun-2005	6-Jul-2010	5.950%				5.950%	-	-	
10	Series 7 RDDA Sub Debt	1-Jun-2007	26-Jun-2012	7.370%				7.370%	-	125	
11									-	-	
12	Less: RDDA Sub Debt Adjustment								-	261	
13								Total with Sub Debt	$289,659	$17,495	x-ref Schedule 69
14								Average Embedded Cost before Sub Debt		5.950%	

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
EMBEDDED COST OF LONG-TERM DEBT Schedule 73
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
1	Long Term Debt 1	16-Feb-2006	15-Feb-2038	6.050%	$250,000	2,014	$247,986	6.108%	$250,000	$15,270	
2	Long Term Debt 2	1-Oct-2010	1-Oct-2039	6.004%	100,000	1,000	99,000	6.078%	100,000	6,078	
3	Long Term Debt 3	1-Oct-2011	1-Oct-2041	6.892%	100,000	1,000	99,000	6.972%	25,205	1,757	
4	PCEPA Repayment Loan	1-Jan-2008	1-Jan-2013	4.880%	15,526	-	15,526	5.181%	15,526	804	
5	Long Term (Rate Base) Debt				465,526	4,014	461,512		390,731	23,909	
6	Series 1 RDDA Sub Debt	1-Jun-2006	11-Jan-2011	7.280%				7.280%	-	-	
7	Series 2 RDDA Sub Debt	1-Jun-2002	31-Jul-2012	7.370%				7.370%	-	-	
8	Series 4 RDDA Sub Debt	1-Jun-2004	14-May-2009	6.820%				6.820%	-	-	
9	Series 5 RDDA Sub Debt	1-Jun-2005	6-Jul-2010	5.950%				5.950%	-	-	
10	Series 7 RDDA Sub Debt	1-Jun-2007	26-Jun-2012	7.370%				7.370%	-	-	
11									-	-	
12	RDDA Subtotal								-	-	
13								Total with Sub Debt	$390,731	$23,909	x-ref Schedule 69
14								Average Embedded Cost before Sub Debt		6.119%	

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
Schedule 74

RDDA CONTINUITY
FOR THE YEARS ENDING DECEMBER 31, 2007 - 2009
In Dollars

Line No.	Particulars	Approved 2007	Actual 2008	Projected 2009	Reference
	(1)	(2)	(3)	(5)	(6)
1	**Opening Balance**	$41,626,420	$ 27,907,609	$ 7,149,120	
2	Deemed Interest on Subordinated Debt	$ 3,207,564	$ 2,481,026	$ 1,269,953	
3	Annual Revenue Surplus Allocated to Sub Debt Interest Payment	(3,207,564)	(2,481,026)	(1,269,953)	
4	Annual Revenue Surplus Allocated to RDDA Amortization	(13,718,811)	(20,758,489)	(7,149,120)	*See Note
5	**Closing Balance**	$ 27,907,609	$ 7,149,120	$ -	

*2009 is projected to be the first year where the Annual Revenue Surplus is greater than the sum of the Opening Balance and the Subt Debt Interest. The remainer of the surplus not shown as allocated to either Sub Debt Interest Payment or RDDA Amortization has been allocated to the 2009 Revenue Surplus Deferral Account.

Terasen Gas (Vancouver Island) Inc. 2010-2011 Revenue Requirements Application
Negotiated Settlement Process
Issues of Particular Concern to the Commission Panel

In accordance with sections 3 and 9 of the Negotiated Settlement Process-Policy, Procedures and Guidelines, the Commission Panel has identified the following issues of particular concern that parties should be aware of during the negotiations:

1. EEC Program-TGVI is to provide results of the programs approved by the EEC Decision and expectations for new programs before the Commission Panel will approve additional EEC program funding.

2. Natural Gas for Vehicles ("NGV")-if NGV is to proceed why should the natural gas ratepayer fund this initiative rather than Terasen's non-regulated businesses or the competitive market?

3. Biogas-could be reviewed by a CPCN which demonstrates market uptake of customers that are willing to pay the full cost.

4. International Financial Reporting Standards ("IFRS")-could have no IFRS impact in 2010.

5. 2010 Rate Changes-in the event that a 2010 rate reduction were to occur as a result of the negotiations, the current rates should remain unchanged and place the revenue surplus into a deferral account to apply against 2011 and future rate increases with a phase in amortization that strives for rate stability.

6. CPCN threshold-why should the threshold increase from $5 million.

7. Unrealized losses in rate base-should some of these losses be to the shareholder? Parties should present a separate settlement package.

8. Rate Design-should BC Hydro receive any refund for the expected 2009 RDDA surplus?

The
British Columbia
Public Interest
Advocacy Centre

208–1090 West Pender Street
Vancouver, BC V6E 2N7
Coast Salish Territory
Tel: (604) 687-3063 Fax: (604) 682-7896
email: bcpiac@bcpiac.com
http://www.bcpiac.com

Valerie Conrad	687-3017
Sarah Khan	687-4134
Eugene Kung	687-3006
James L. Quail	687-3034
Ros Salvador	488-1315
Leigha Worth	687-3044

Barristers & Solicitors

Peggy Lee
Article Student

Our file: 7430

November 12, 2009

VIA EMAIL

Erica M. Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Re: Terasen Gas Vancouver Island Inc. Revenue Requirements 2010-2011 Negotiated Settlement

This is to confirm, that we are satisfied that the draft Settlement Agreement circulated by Mr. Thompson and Mr. Loski on November 5, 2009 accurately captures the consensus reached by the parties to the Negotiated Settlement Process in this proceeding, and that we have been instructed by our clients, BCOAPO et al., to endorse it.

Accordingly, we ask that the Commission incorporate it into a consent Order for the resolution of all issues in the Application.

Our only further comments, made here only "for the record" and in no way detracting from our clients' endorsement of the Settlement, concern the “Alternative Energy Solutions" addressed under heading 8 of the document. While we believe that the ultimately appropriate corporate and regulatory formats for these lines of business are subject-matters which may require eventual determination by the Commission, our clients are content with the treatment of these issues in the Settlement Agreement over its term, in that it provides a “firewall” to ensure that the utility’s natural gas distribution customers do not subsidize or otherwise contribute to these nascent programs through their rates.

Yours truly,

BC PUBLIC INTEREST ADVOCACY CENTRE

Original in filed signed by:

Jim Quail
Executive Director

cc: parties of record

OWEN • BIRD
LAW CORPORATION

PO Box 49130
Three Bentall Centre
2900-595 Burrard Street
Vancouver, BC
Canada V7X 1J5

Telephone 604 688-0401
Fax 604 688-2827
Website www.owenbird.com

Direct Line: 604 691-7557
Direct Fax: 604 632-4482
E-mail: cweafer@owenbird.com
Our File: 23841/0040

November 13, 2009

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C. V6Z 2N3

Attention: Erica M. Hamilton,
Commission Secretary

Dear Sirs/Mesdames:

Re: Terasen Gas (Vancouver Island) Inc. ("TGVI") 2010 and 2011 Revenue Requirements and Rate Design Application, Project No. 3698563

We are counsel to the Commercial Energy Consumers Association of British Columbia (the "CEC"). We confirm that the CEC accepts the terms of the final version of the Negotiated Settlement Agreement on the above-noted Application circulated by TGVI on November 5, 2009 and have no comments on that draft.

The CEC thanks the Commission staff and facilitator, TGVI and the other customer representatives for their efforts during these negotiations.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer
CPW/jlb
cc: CEC
cc: TGVI
cc: Registered Intervenors

CPW20097

BC hydro
FOR GENERATIONS

Leon Cender
Manager, Power Acquisitions
Phone: (604) 623-4436
Fax: (604) 623-4335
Email: leon.cender@bchydro.com

November 13, 2009

Ms. Erica M. Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

RE: Project No. 3698563
British Columbia Utilities Commission (BCUC)
British Columbia Hydro and Power Authority (BC Hydro)
Terasen Gas (Vancouver Island) Inc. 2010 and 2011 Revenue Requirements and Rate Design Application - Negotiated Settlement Agreement

BC Hydro acknowledges receipt of the final version of the Negotiated Settlement Agreement from Terasen Gas (Vancouver Island) Inc. (TGVI) and that the company has reviewed the document.

BC Hydro accepts the Negotiated Settlement Agreement and confirms that it has taken no position with respect to matters reflected in the Negotiated Settlement Agreement other than matters related to the Rate Design and those referred to in items 21 and 22 of the Negotiated Settlement Agreement.

Yours sincerely,

Leon Cender

Leon Cender
Manager, Power Acquisitions

cc. BCUC: Philip Nakoneshny
TGVI – Tom Loski
BCOAPO et al. – Jim Quail
CEC – Chris Weafer

IN THE MATTER OF

TERASEN GAS INC.
TERASEN GAS (VANCOUVER ISLAND) INC.

AND

ENERGY EFFICIENCY AND CONSERVATION APPLICATION

DECISION

April 16, 2009

Before:

A.W.K. Anderson, Commissioner
A.A. Rhodes, Commissioner

TABLE OF CONTENTS

TABLE OF CONTENTS

1.0 BACKGROUND AND REGULATORY PROCESS

1.1 The Application

On May 28, 2008 Terasen Gas Inc. ("TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI") (collectively "Terasen") filed its Energy Efficiency and Conservation ("EEC") Programs Application ("Application") with the British Columbia Utilities Commission ("the Commission").

In the Application, Terasen requested an order or orders approving the following:

- Increases of EEC expenditures in the period 2008-2010 to $46.944 million for TGI and $9.667 million for TGVI, a combined total of $56.6 million;
- Capitalisation of incremental EEC expenditures as a regulatory asset deferral account on an after tax basis and amortisation of the account over 20 years;
- An increase in the amortisation period to 20 years for incentive amounts that are added to deferral accounts for 2008 and 2009 as part of the 2008-2009 extension of the 2004-2007 TGI PBR Settlement Agreement ("TGI PBR Extended Settlement") approved by Order G-33-07 and the 2008-2009 extension of the 2006-2007 TGVI Revenue Requirements Settlement Agreement ("TGVI RR Extended Settlement") approved by Order G-34-07;
- Changes to the benefit-cost analysis undertaken to evaluate EEC measures as outlined below:
    - Implementation of a portfolio approach to benefit-cost analysis such that the Total Resource Cost ("TRC") test for all programs combined must return an overall combined result of one or more;
    - Elimination of the requirement to include free-riders in benefit-cost tests;
    - Inclusion of the benefits of savings associated with implementation of a regulation as a result of EEC programs aimed at preparing the marketplace for the introduction of regulation of minimum efficiency levels in equipment, buildings or energy systems
    - Inclusion of the impact of carbon-pricing as one of the inputs to the benefit-cost tests;

- A requirement that Terasen submit annually to the Commission, by the end of the first quarter following year-end, for each year of the funding period, a report on all EEC initiatives and activities, expenditures and results for TGI and TGVI.

The Commission directed that the Application would follow a written hearing process after hearing submissions from intervenors and interested parties.

Intervenors registered for the hearing were:

- British Columbia Hydro and Power Authority (“BC Hydro”),
- British Columbia Old Age Pensioners’ Organization et. al. (“BCOAPO”),
- B.C. Sustainable Energy Association and the Sierra Club of Canada (British Columbia Chapter) (collectively, “BCSEA-SCBC”),
- The Ministry of Energy, Mines and Petroleum Resources (“MEMPR”),
- The Rental Owners and Managers Society of B.C. (“ROMS”),
- FortisBC Inc.,
- Pacific Northern Gas Ltd. (“PNG”),
- The Commercial Energy Consumers Association of BC (“CEC”) and
- Direct Energy Marketing Limited

In addition to parties registering as intervenors, numerous letters of comment were received.

Two rounds of Information Requests were conducted.

Intervenors BC Hydro and BCSEA-SCBC also filed evidence.

The process was complete on December 5, 2008 with the filing of Terasen’s reply submission.

1.2 Legal and Regulatory

1.2.1 The Utilities Commission Act

The Application is made pursuant to Section 44.2 of the Act, which states, in part:

> "(1) A public utility may file with the commission an expenditure schedule containing one or more of the following:
>
> > (a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;…"

and:

> "(3) After reviewing an expenditure schedule submitted under subsection (1), the commission, subject to subsections (5) and (6), must
>
> > (a) accept the schedule, if the commission considers that making the expenditures referred to in the schedule would be in the public interest, or
> >
> > (b) reject the schedule.
>
> (4) The commission may accept or reject, under subsection (3), a part of a schedule.
>
> (5) In considering whether to accept an expenditure schedule, the commission must consider
>
> > (a) the government's energy objectives,
> >
> > (b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,
> >
> > (c) whether the schedule is consistent with the requirements under section 64.01 or 64.02, if applicable,
> >
> > (d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any, and
> >
> > (e) the interests of persons in British Columbia who receive or may receive service from the public utility.
>
> (6) If the commission considers that an expenditure in an expenditure schedule was determined to be in the public interest in the course of determining that a long-term resource plan was in the public interest under section 44.1 (6),

(a) subsection (5) of this section does not apply with respect to that expenditure, and

(b) the commission must accept under subsection (3) the expenditure in the expenditure schedule."

1.2.2 The Long Term Resource Plan

The Commission Panel notes that, with respect to subsection 44.2 (5) (b) and subsection 44.2(6), Terasen filed its consolidated 2008 Resource Plan (on behalf of TGI, TGVI and Terasen Gas (Whistler) Inc.) on June 27, 2008, which was accepted as described in Order G-194-08 and its accompanying Reasons. As noted in the Reasons, the Commission Panel specifically excluded any consideration or determination with respect to whether the EEC expenditures included in the instant Application were in the public interest. Accordingly, the Commission Panel considers that subsection 5 of s. 44.2 is applicable to the Application, whereas subsection 44.2(6) is not.

1.2.3 'Cost effectiveness' and the Demand Side Measures (DSM) Regulation

Subsection 44.2 (5)(d) requires the Commission to consider whether the EEC expenditures are ". . . cost-effective within the meaning prescribed by regulation, if any, . . .".

On November 7, 2008, the Government issued Ministerial Order M271/2008 which attached B.C. Reg. 326/2008 - Demand-Side Measures Regulation. Section 3 of the DSM Regulation deals with the "adequacy" of a demand-side measures "plan portfolio" and section 4 of the DSM Regulation sets forth certain requirements with respect to the determination of whether such expenditures are "cost effective". Section 2 of the DSM Regulation provides that the regulation applies only to 'the authority' (BC Hydro) until June 1, 2009, at which time the regulation will become more generally applicable. Accordingly the requirements of sections 3 and 4 are not applicable to Terasen's current EEC Application.

1.2.4 BC Government's Energy Objectives

Subsection 44.2 (5)(a) of the Act requires the Commission to consider the "government's energy objectives" in considering whether to accept an expenditure schedule. The "government's energy objectives" are defined in section 1 of the Act as follows:

> "(a) to encourage public utilities to reduce greenhouse gas emissions;
>
> (b) to encourage public utilities to take demand-side measures;
>
> (c) to encourage public utilities to produce, generate and acquire electricity from clean or renewable sources;
>
> (d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility;
>
> (e) to encourage public utilities to use innovative energy technologies
>
> > (i) that facilitate electricity self-sufficiency or the fulfillment of their long-term transmission requirements, or
> >
> > (ii) that support energy conservation or efficiency or the use of clean or renewable sources of energy;
>
> (f) to encourage public utilities to take prescribed actions in support of any other goals prescribed by regulation…"

2.0 TERASEN'S PROPOSED EEC EXPENDITURES

Terasen is applying for approval of an increase in allowed expenditures for EEC activity for TGI and TGVI to a total of approximately $56.6 million over the three year Program Period 2008 to 2010, an increment of $48.062 million over currently approved DSM spending for the two utilities. (Exhibit B-1, p. 8)

The proposed EEC Expenditures, by Program Area, by Utility, are set out in the table below.

Table 1

($000)

Spend by Program Area 2008 -2010	**TGI**	**TGVI**	**Total**
Residential Energy Efficiency	8,552	734	9,286
Commercial Energy Efficiency	19,592	2,199	21,791
Residential Fuel Switching	1,332	2,367	3,699
Conservation Education and Outreach	11,068	2,767	13,835
Joint Initiatives	2,400	600	3,000
Trade Relations	1,200	300	1,500
Conservation Potential Review	400	100	500
Innovative Technologies, NGV and Measurement	2,400	600	3,000
Total	46,944	9,667	56,611

(Source: Exhibit B-1, p. 9)

Terasen states that it is most efficient for the Commission to approve the overall expenditure level, by utility, for the funding period rather than by approving the funding by program area or by individual program initiative. Terasen submits that this approach will allow it to respond quickly to changes within initiatives and to new opportunities that might arise, and will reduce the administrative burden related to EEC activity. (Exhibit B-1, pp. 50-51)

Terasen also submits that the energy savings from the EEC expenditures will result in savings with a present value of almost 10 million gigajoules ("GJs") over the lives of the various measures proposed, while fuel switching activity is estimated to result in approximately 2.3 million GJs of additional load. The anticipated present value of net energy savings is approximately 7.7 million GJs, not including potential savings arising from Conservation Education and Outreach, Joint Initiatives or Innovative Technologies, NGV and Measurement program areas. (Exhibit B-1, p. 10) Terasen further states that DSM expenditures at current levels would result in cumulative annual savings of 1.3 million (nominal, rather than present value) GJs by 2016, whereas the proposed expenditures would result in cumulative annual savings of approximately 6.4 million nominal GJs in the same time period. (Exhibit B-1, p. 11)

2.1 Residential and Commercial Energy Efficiency

Terasen developed its budget estimates for Residential Energy Efficiency, Commercial Energy Efficiency and Residential Fuel Switching based on work done in 2006 in its Conservation Potential Review ("CPR"). Those estimates were refined by Habart and Associates Consulting Inc. ("Habart") as described in Habart's September 2007 Report ("Habart Report") provided in Appendix 9 of the Application. (Exhibit B-1, p. 52) The Habart Report concluded that total DSM funding of approximately $35 million over the three-year period would be required. (Exhibit B-1, Appendix 9, p. 23)

Terasen states that "[t]he key finding of the CPR was the Achievable Potential" which is a measure of savings which could realistically be achieved within the study period. (Exhibit B-1, p. 45) The Achievable Potential from the CPR is outlined in the table below:

Table 2

CPR Findings

By 2015/2016, GJ per year	TGVI	Lower Mainland	Interior	Total
Residential EE	-369,000	-5,298,000	-1,847,000	-7,514,000
Commercial EE	-385,000	-1,396,000	-431,000	-2,212,000
Industrial EE	-32,430	-933,064	-924,210	-1,889,704
Subtotal	**-786,430**	**-7,627,064**	**-3,202,210**	**-11,615,704**
Residential Fuel Subsitution				1,453,000
Potential Annual Impact				**-10,162,704**

(Exhibit B-1, Table 4.1, p. 45)

Terasen states that "[t]he strategies outlined in this Application, and the expenditures for which approval is being sought, are based to a significant degree on the findings of the CPR and the subsequent work undertaken with Habart." (Exhibit B-1, p. E-3)

In discussing estimation of new dwelling heating loads, the 2006 CPR states that: "[d]iscussions with provincial government staff indicated that a number of changes to residential buildings are under consideration that could affect the thermal performance of British Columbia's new housing over the study period." The changes being considered include targets for new construction, including residential buildings and all commercial buildings (including apartments) and strategies to achieve improved thermal performance in related residential equipment and products, including furnaces, fireplaces, and windows. (Exhibit B-1, Appendix 1, p. 33)

2.1.1 Residential Energy Efficiency

Terasen proposes spending $9.286 million on Residential Energy Efficiency for both TGI and TGVI over the Program Period (Exhibit B-1, p. 55, Table 6.2b). The Residential Energy Efficiency program area includes both new construction and retrofit initiatives.

2.1.1.1 New Construction

For new construction, Terasen is proposing EnerChoice Fireplace and Energy Star Appliance initiatives. The EnerChoice Fireplace program will provide an incentive to customers who purchase and install an EnerChoice rated fireplace, insert or free-standing stove. The Energy Star Appliance program provides incentives for customers who use natural gas for domestic hot water ("DHW") heating to install Energy Star clothes washers and/or dishwashers. (Exhibit B-1, p. 59)

Terasen states "[t]he key decision makers in this market for the [new construction] programs . . . are builders and developers who build single family homes and row-houses" and ". . . new construction EEC portfolio in the residential market will include programs that encourage customers, whether they be individuals building a new home, or builders and developers, to install <u>energy efficient</u> appliances." (Exhibit B-1, p. 58) (emphasis in original)

2.1.1.2 Retrofit

For the residential retrofit market Terasen is proposing an Energy Star Heating System Upgrade program that will reprise earlier versions of this program, and will provide customers who install an Energy Star heating system a credit on their Terasen bill for gas service. Terasen's Application is based on funding for incentives for gas furnace upgrades in single family dwellings ("SFDs") and duplexes in the Terasen service territory. Terasen estimates upgrades to 5.3 percent of the stock of pre-1976 SFDs and duplexes or 8,180 furnace upgrades to the end of 2009. Terasen notes that due to expected new Federal government regulations requiring all furnaces sold in Canada to meet a minimum standard of 90 percent efficiency after December 31, 2009, this program will conclude prior to that date. (Exhibit B-1, pp. 59-60)

Terasen is also proposing EnerChoice Fireplace and Energy Star Appliance programs for the retrofit market as for the new construction market. The Hearth, Patio & Barbeque Association of Canada will provide assistance in promotional and educational aspects of the EnerChoice Fireplace program. (Exhibit B-1, p. 60)

The residential sector expenditures proposed by Terasen, by utility and program area are as follows:

Table 3

TGI and TGVI Energy Efficiency ($000)		2008	2009	2010	Total
TGI	New Construction	411	566	1,056	2,033
	Retrofit	2,495	2,658	1,367	6,520
	Sub total, TGI	2,906	3,224	2,423	8,553
TGVI	New Construction	130	156	232	518
	Retrofit	53	66	97	216
	Sub total, TGVI	183	222	329	734
	Total	3,089	3,446	2,752	9,287

Source: BCUC IR No. 1 Attach 56.2A

2.1.1.3 Commercial Energy Efficiency

Terasen is proposing to spend $21.7 million on commercial sector new construction and retrofit programs (Exhibit B-1, p. 60). The expenditure proposals were based on refinements of the following initial recommendations from the Habart report:

Table 4

TGI and TGVI Commercial Programs	Spending 2008-2010 ($000) TGI	TGVI
New Construction		
Efficient New Construction	5,297	727
Boilers	1,928	224
Water Heating	1,118	103
Subtotal - New Construction	**8,343**	**1,055**
Retrofit		
Boilers	7,395	1,074
Building Recommissioning	3,095	354
Next Generation Building Automation Systems	968	95
Demand Control Ventilation	1,795	-
High Efficiency Rooftop Units	239	17
Water Heat	2,032	254
Subtotal - Retrofit	**15,524**	**1,794**
Total Commercial Energy Efficiency	**23,867**	**2,849**

Source: Exhibit B-2, Attachment 56 2A TGVI and 56 2A TGI

2.1.1.4 New Construction

The commercial new construction program is aimed at all new construction "…which might use natural gas space and water heating." Terasen states that "…the immediate opportunities are likely to be Multifamily Dwellings ("MFDs") and Commercial office space" and may also include some institutional buildings. (Exhibit B-1, p. 61) Terasen lists some potential areas for activity in the commercial new construction sector, and notes that program design in this sector is complex, so the program activities listed in the Application are merely summaries.

Terasen states "[t]he key decision makers in this market are owners including: governments; builders/developers; architects; engineers; interior designers; mechanical consultants; and contractors." (Exhibit B-1, p. 61)

The new construction energy efficiency program areas include initiatives aimed at:

- Efficient New Construction Design and High Insulation Technology for windows;
- Condensing and near condensing boilers; and
- Instantaneous and condensing DHW heaters and drain water heat recovery.

(Exhibit B-1, Table 6.3.2, p. 61)

<u>2.1.2.5 Retrofit</u>

Terasen's commercial retrofit program is aimed at all commercial and industrial buildings with existing natural gas space and water heating equipment. Terasen again notes that, due to the complexity of programs in this sector, it has merely summarized areas of program activity and states "[m]ore detailed program development work must be completed by [Terasen] in conjunction with industry groups before these programs are rolled out." (Exhibit B-1, p. 62)
Commercial retrofit energy efficiency program area activity includes initiatives for:

- Condensing and near condensing boilers
- Building Recommissioning
- Next Generation Building Automation Systems ("BAS")
- High Efficiency ("HE") Rooftop Units
- Instantaneous and condensing DHW boilers and heaters
- For TGI only, Terasen is proposing to add: demand control ventilation for large and medium commercial buildings and drainwater heat recovery.

(Exhibit B-1, p. 62, Table 6.3.2a)

Terasen states that commercial sector programs are intended to offer qualified customers a menu of programs from which to choose and that Terasen staff will work with participants in selecting the most appropriate program and/or component. (Exhibit B-1, p. 63)

Intervenor Positions

BCOAPO takes issue with the relative allocation of spending as between proposed residential and commercial customer groups. BCOAPO notes that residential customers make up 90 percent of Terasen's total customers and 38 percent of its total volume, whereas commercial customers represent only 9.7 percent of its customer base and 26 percent of its total volume. (BCOAPO Argument, p. 12)

Commission Determination

The Commission Panel notes BCOAPO's comments as well as the CPR evidence indicating that some 70 percent of the Achievable Potential savings are associated with the residential sector. Terasen has included residential market MFDs in its Commercial EE program, which, in the view of the Commission Panel, may also have significant potential for low income housing initiatives. Terasen indicates that it will re-direct funding amongst programs based on customer response, thus enabling funding balancing between Residential and Commercial programs as appropriate.

The Commission Panel finds the design of Terasen's Residential and Commercial EE programs to be reasonable, flexible and in the public interest, and accepts the expenditure proposals for these program areas.

2.2 Residential Fuel Switching

Reduction in Greenhouse Gas (“GHG”) emissions is advanced by Terasen as a benefit in support of residential fuel switching for TGI. The stated premise is that the substitution of natural gas for electricity will reduce overall GHG emissions in the short term, by increasing the amount of electricity available to BC Hydro to meet domestic load, thereby reducing its dependence on imported power or, alternatively, allowing it to increase exports of clean power, thus enabling a reduction in the regional use of gas or coal-fired power. Terasen submits, over the longer term, to the extent BC Hydro is able to meet its load requirements, excess clean generation could be exported, displacing the use of gas and/or coal-fired generation in the region (Western Interconnection). (Exhibit B-1, p. 63; Terasen Reply, p. 5)

Terasen states that “[t]he primary objective of the fuel-switching offers is to promote the most optimal balance in energy share between electricity and natural gas, preserving BC Hydro’s generation and transmission systems for its [sic] highest value – in running lights, computers and other technology.” (Exhibit B-1, p. 64)

Terasen proposes to spend $3.7 million in the residential fuel switching program area. It is proposing that only new construction fuel switching programs be offered in the TGI service area but that both new construction and retrofit fuel switching programs be offered in the TGVI service area.

Terasen proposes to spend the following amounts on fuel switching programs annually, over the Funding Period.

Table 5

Residential Fuel Switching Programs

Program		**Initiatives**	**TGI**	**TGVI**
New Construction				
	Natural Gas Water Heating	NG DHW	319	693
	Natural Gas Appliances	NG Range	1,013	50
		Sub Total	1,332	743
Retrofits		NG Dryer		38
	Natural Gas Appliances	FS Range	-	247
		FS Dryer	-	247
	Furnace Fuel Substitution	Furnace	-	766
	Fireplace Fuel Substitution	EnerChoice Fireplace	-	326
		Sub-total		1624
		Totals	1332	2367

Source: Exhibit B-2, Attachments 56.2A 2 (TGI) and 56.2A 4 TGVI

New Construction

All new construction expenditures involve fuel switching from electricity. Only the Retrofit programs, which are limited to Vancouver Island, involve potential fuel switching from propane, oil or wood in addition to electricity. Terasen states: "[i]t is very challenging to separate out proposed expenditures for fuel switching from electricity to natural gas from vs. [sic] proposed expenditures for fuel switching from non-electric sources to natural gas, as there are a number of potential energy sources for the proposed TGVI residential retrofit program, and …[it] cannot predict the proportion of participants switching from each energy source." (Exhibit B-5, BC Hydro 1.1.1)

Terasen proposes fuel substitution incentive programs to encourage the use of natural gas in new construction projects for installation of natural gas domestic hot water heaters in the TGVI service area and to install a natural gas range and/or dryer in both the TGI and TGVI service areas. (Exhibit B-1, p. 64)

Retrofit

Incentive funding for fuel substitution retrofits is only contemplated for TGVI, as many households in its service territory still use wood, propane or fuel oil for space heating and fireplaces.

The proposed programs include incentive payments for:

- Switching to natural gas for space heating and for installing Energy Star equipment. Terasen states that "the current regulatory regime for TGVI does not allow Terasen to offer customers who switch to natural gas an incentive to install Energy Star equipment." (Terasen proposes that it be able to offer both, but also advises that it would restrict the incentive to furnaces and boilers rated Energy Star.);
- Installation of an EnerChoice-rated fireplace, insert or free-standing stove; and
- Replacement of existing electric or propane ranges and dryers with gas appliances.

(Exhibit B-1, p. 65)

Intervenor Positions

BCOAPO strongly opposes the inclusion of any expenditures associated with fuel switching away from electricity to natural gas in Terasen's EEC portfolio. BCOAPO argues that there is no evidence as to an "optimal balance" as between electricity and natural gas and suggests that a movement away from (clean) electricity to a fossil fuel would not be part of such optimal balance. (BCOAPO Argument, p. 10)

BC Hydro filed the evidence of Randy Reimann, P. Eng., its manager of Resource Planning, wherein he contradicted Terasen's assertion that fuel switching away from electricity to natural gas would reduce the need for BC Hydro to import electricity from other jurisdictions which rely on coal or natural gas for generation. Mr. Reimann stated: "[t]here is no medium to long term linkage between fuel switching from electricity to natural gas and a change in BC Hydro's need for importing electric energy or ability to export such energy." (Exhibit C2-6, Direct Testimony of Randy Reimann, p. 2, Q.7)

BC Hydro also filed the evidence of Patrice Rother, its manager of Environmental Strategy in the Safety, Health and Environmental group. Ms. Rother reviewed recent GHG-related legislative and policy developments including the B.C. Greenhouse Gas Reduction Targets Act ("GGRTA"), the B.C. Climate Action Plan and the joinder of British Columbia into the Western Climate Initiative and highlighted a number of areas of uncertainty surrounding how the WCI GHG trading scheme will align with the GGRTA legislated targets and other Chinook Action Plan action items on a regional basis. (Exhibit C2-6, Direct Testimony of Patrice Rother pp. 2-3, Q. 8, 11)

Commission Determination

While the Commission Panel notes the comments of Terasen regarding potential GHG benefits of fuel switching, particularly away from fossil fuels with a higher carbon content than natural gas, the Commission Panel is not convinced that expenditures on fuel switching and load building away from electricity can be properly considered in a portfolio of EEC programs at this time. The Commission Panel agrees with the comments of the BCOAPO that the "optimal balance" as between natural gas and electricity has not been established. The Commission Panel also finds that the efficiency of other energy sources over and above that of electricity has not been adequately established.

The Commission Panel also notes that natural gas does have a GHG impact which is not present in clean domestic electricity and that one of the government's energy objectives is "to encourage public utilities to reduce GHG emissions." The Commission Panel accepts the evidence of

Ms. Rother that there is considerable uncertainty, at this time, surrounding how various government initiatives will align on a regional basis. The Commission Panel finds that Terasen has not provided sufficient evidence to persuade the Panel, on a balance of probabilities, that a regional approach should be adopted as a justification for EEC expenditures aimed at substituting natural gas as a fuel to replace electricity.

The Commission Panel accepts EEC expenditures directed at fuel switching from fossil fuels with a higher carbon content than that of natural gas. Expenditure programs specifically directed at encouraging fuel switching away from electricity are rejected, as are Incentive payments for appliances for which an Energy Star rating is not available. However, expenditures are accepted for incentives to install Energy Star and EnerChoice equipment and appliances for customers who, at their own initiative, wish to switch to natural gas as the fuel of choice.

2.3 Conservation Education and Outreach

This proposal is in addition to program-specific education and outreach funding, and relates to non-program-specific activities, as set out below.

- Terasen's proposed budget for Conservation Education and Outreach (CEO) was developed in consultation with Wasserman + Partners Advertising ("Wasserman"). Terasen proposes a total CEO expenditure of $13.835 million in the 2008 to 2010 period which is 24 percent of the total EEC proposed expenditures of $56.611 million. The Wasserman proposal states that the planned messaging will educate the public about Terasen's EEC program and related activities.

(Exhibit B-1, Appendix 8)

Terasen was requested to describe the specifics of the CEO programs and responded that these initiatives ". . . have not yet been fully developed, however, as outlined on page 65 of the Application, they are projected to include:

- Stakeholder industry group activities, such as first time homebuyers seminars
- Public outreach by "Team Terasen"
- Support for conservation education within the school system
- Energy Forum
- Conservation communications, as outlined in Appendix 8 in the Application."

(Exhibit B-2, BCUC 1.28.1)

The entire proposed $13.835 expenditure for the CEO Program Area is taken by the Conservation communications initiative of the CEO Program. $11.550 million or 83 percent of the $13.835 million is allocated to Mass Media Advertising and Production over the three year expenditure period. (Exhibit B-1, Appendix 8)

Terasen did not submit any details or expenditure estimates for the first four program initiatives described above.

Terasen proposes to attribute the CEO expenditures in each year equally between the Residential and Commercial Energy Efficiency programs, with none of the CEO expenditures being attributed to other Program Areas such as Fuel Switching or Trade Relations. (Exhibit B-1, p. 54)

Terasen states: "EEC expenditures will be efficient, with non-incentive costs not exceeding 50% of the expenditure in a given year." (Exhibit B-1, p. 47, #3) Terasen does not provide any further evidence supporting the implication that, merely by not exceeding 50 percent of the total, non-incentive, expenditures, the balance represents efficiency in expenditures.

<u>Intervenor Positions</u>

BCOAPO submitted that "The Application's education and outreach component is disproportionately large, and inappropriately treated as an asset to be amorti[s]ed over 20 years." (BCOAPO Argument, p. 14)

BCSEA-SCBC submitted the evidence of John J. Plunkett of Green Energy Economics Group, Inc. The Commission Panel reviewed Mr. Plunkett's qualifications and experience and accepts him as an expert with respect to the matters his testimony addresses in this Application.

Mr. Plunkett proposes that the CEO should be reduced by 50 percent, and the amount by which the funding is reduced be redirected to the residential and commercial efficiency programs.
Mr. Plunkett notes that while building a conservation 'ethic' in British Columbia is laudable, the primary purpose of the CEO expenditures should be to support the efficiency programs.
(Exhibit C5-5, pp. 18, 19)

Commission Determination

The Commission Panel finds that Terasen has not provided sufficient evidence to support either the $13.835 million total proposed EEC expenditures, or the allocation of some 84 percent of that amount to mass media advertising and production. The Commission Panel notes that the Commercial component comprises some 70 percent of the total expenditures in the combined Residential and Commercial Energy Efficiency program areas, to which the CEO costs have been attributed equally. The Commission Panel also notes Terasen's comments, quoted above, with respect to the key decision makers in both the new and retrofit commercial markets. The Commission Panel considers both these markets to be significantly more narrow and focused than markets which may warrant the use of mass media approaches to communication.

The Commission Panel also notes that Terasen's evidence did not include any discussion of bill stuffers or other communication methods.

The Commission Panel agrees in part with Mr. Plunkett's proposal, and considers that, while public education is an appropriate activity in support of the EEC objectives, the evidence is not sufficient to support either the full amount proposed or the allocation of the proposed CEO expenditures. The Commission panel does not agree with Mr. Plunkett's suggestion that the funding reduction of the CEO expenditures be redirected to the energy efficiency programs. The Commission Panel finds the evidence sufficient to establish that there is a benefit to some CEO expenditures and accepts 50 percent, $6.918 million, as reasonable.

Terasen is directed to review the CEO program with a view to:

- altering the program to allocate funds away from the mass media campaign and to include other initiatives, with particular attention paid to conservation education within the school system and affordable housing initiatives;
- addressing the apparent imbalance of the residential to commercial expenditure ratio, approximately 30:70, in comparison to the ratio of residential to commercial Achievable Potential GJ impact of approximately 77:23 (Exhibit B-1, p. 45);
- reconsidering the apparent lack of communication expenditures directed in a focused manner to the Commercial Energy Efficiency program,
- reconsidering appropriate attribution of CEO costs to Program Areas and initiatives, and any related impact on Total Resource Cost calculations and rate impacts.

2.4 Joint Initiatives, Trade Relations, 2009 CPR, and Innovative Technologies, NGV and Measurement

2.4.1 Joint Initiatives

Terasen is requesting that $1.0 million per year be approved for the development of Joint Initiatives as they arise. Initiatives that Terasen states it will, or may pursue if the funding is approved, include: support for audits for a Provincial Home Retrofit Program, DSM for affordable housing, building labeling, and community action on energy efficiency. (Exhibit B-1, pp. 66-68)

2.4.1.1 Audits

The "audit" joint initiative involves providing financial assistance to customers by paying for the cost of a pre or post upgrade audit, both of which are necessary for participation in the federal government's "Eco-Energy" program. This initiative would support the provincial government's expressed intention to implement a province-wide home retrofit program, "LiveSmartBC", to complement the federal government initiative. The provincial program does not contemplate paying the cost of post-retrofit audits, and Terasen sees an opportunity to provide full or partial funding to enable more of its customers to participate in the programs. (Exhibit B-1, pp. 43, 67)

2.4.1.2 Affordable Housing

Terasen states that "[t]he Ministry of Energy Mines and Petroleum Resources has asked that the Terasen Utilities lead a working group on DSM for Affordable Housing, the goal of which is to find ways and means to deliver Energy Efficiency to the Affordable Housing sector in B.C. and that such group has been convened. Terasen proposes to fund its participation in any resulting DSM incentive program from the Joint Initiatives Program allocation. (Exhibit B-1, p. 67)

2.4.1.3 Labeling

A further joint initiative which Terasen proposes is to co-fund a pilot project to label homes and buildings with an energy consumption/efficiency rating. Terasen states that this will assist in informing the public and promoting energy conservation and will enable comparisons as between different gas-heated homes.

2.4.1.4 Community Action

Terasen also proposes to make a financial contribution to the pool of funds to which municipalities can apply under the "Community Action on Energy Efficiency" initiative for financial and research support to advance energy conservation and efficiency in their areas, through policy action and public outreach. (Exhibit B-1, p. 68; The BC Energy Plan 2007- Policy Action #9)

Intervenor Positions

BC Hydro supports the Joint Initiatives funding requested. (BC Hydro Argument, p. 5)

BCOAPO argues that this area of the EEC is "drastically under-funded if any meaningful [low-income energy efficiency program ("LIEEP")…is to be developed." (BCOAPO Argument, p. 7)

BCSEA-SCBC argues: ". . . while the four initiatives under the Join Initiatives program area may be worthwhile" they do not satisfactorily address the need for better integration of Terasen's programs with electrical DSM programs as identified by the BCSEA-SCBC expert, Mr. Plunkett. (BCSEA-SCBC Argument, pp. 12-13) Mr. Plunkett recommends that Terasen should be directed to redesign programs by streamlining them and better integrating them with electric efficiency programs. (Exhibit C5-5, p. 5)

Commission Determination

The Commission Panel accepts the expenditures requested for the Joint Initiatives Program area. The Commission Panel notes the comments of the BCOAPO and agrees that the Affordable Housing Initiative appears to be under-funded, particularly given that no portion of the requested global amount for Joint Initiatives is specifically dedicated to Affordable Housing. The Commission Panel also notes that the DSM Regulation which does not yet, but will, apply to Terasen requires that a public utility's plan portfolio include "a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption". The Commission Panel therefore directs Terasen to proceed with its Joint Initiative relating to Affordable Housing and encourages Terasen to consider re-allocating funding from other approved areas of its overall spending as may be suitable.

The Commission Panel concurs with Mr. Plunkett's recommendation, and considers the Joint Initiatives Program to be an appropriate area from which funds should be used to aggressively pursue integrating Terasen's EEC programs with those of the electric utilities in British Columbia. The Commission Panel's view is that integrating the efforts of gas and electric utilities will better encourage customers to take advantage of the programs by eliminating unnecessary duplication in communication, applications, audits and similar time consuming activities.

2.4.2 Trade Relations

The Trade Relations program area is aimed at the support and education of skilled trades, equipment manufacturers, distributors, suppliers and retailers, appliance and equipment salespeople and Realtors. The $1.5 million in funding being requested for Trade Relations with this Application is to support the activities of a Terasen Utilities staff member focused on Trade Relations as it relates to energy efficiency.

Commission Determination

The Commission Panel takes note of Terasen's descriptions of the key decision makers in each of the Residential and Commercial EE programs, referred to previously, as well as the references to the complexity of the commercial new construction and retrofit sector programs and resulting paucity of detail for those program areas. (Exhibit B-1, p. 61)

The Commission Panel considers that the Trade Relations program area expenditures represent a significant duplication of the Residential and Commercial Energy Efficiency programs' non-incentive costs. As noted in the Application, the Energy Efficiency programs will significantly increase the interactions as between Terasen and its customers, and therefore increase "the opportunities for [Terasen] to communicate general conservation information in addition to program-specific information..." (Exhibit B-1, p. 46) The Commission Panel finds the evidence with respect to the details of the Trade Relations program area to be insufficient, and accordingly, this area of expenditure is rejected.

2.4.3 Innovative Technologies, NGV and Measurement

Terasen states that it is in a unique position to foster and further the deployment of forward-looking low carbon technologies, including measurement technologies, and is therefore seeking funding with this Application, specific to this arena. (Exhibit B-1, p. 69)

Terasen states that "[t]he amount for Innovative Technologies, NGV and measurement will need to be refined – if an effective program in Innovative Technologies, NGV and Measurement can be developed over the funding timeframe, the Companies wish to have the ability to fund such a program over the funding timeframe." (Exhibit B-1, pp. 53, 69) Terasen states that the activity in this area would be in the nature of pilot programs, with limited time frames, geographic areas and numbers of installations. The Companies indicate that they would pursue technologies with the same underlying characteristics:

- Each promotes the efficient use of natural gas through sustainable design;
- None are currently a mainstream technology;
- Each offers the potential for at least a 10 percent GHG benefit.

Energy efficiency technologies the Companies would intend to pursue include:

- Residential
  - hydronic based heating systems;
  - Integrated energy systems providing both space heat and DHW;
  - Solar thermal assisted space or DHW systems;

- Commercial
    - hydronic based heating systems;
    - Solar thermal assisted space or DHW systems.

(Exhibit B-1, p. 73)

Terasen states that it would aim fuel-substitution initiatives at both new construction and retrofit markets in both the TGI and TGVI service areas, and notes that fuel-substitution in this category refers to the displacement of natural gas using cleaner renewable technologies. The Companies state that more detailed program development work must be completed by Terasen in conjunction with industry groups before programs are rolled out or funding is allocated. (Exhibit B-1, p. 74)

Commission Determination

The Commission Panel considers that Innovative Technologies, NGV and Measurement programs can be appropriate vehicles for encouraging commercial development of technologies to reduce or replace natural gas consumption and related GHG emissions.

However, as noted above, Terasen acknowledges that further refinement of this program is required and indicates uncertainty as to whether an effective program can be developed over the funding timeframe. The Commission Panel finds that there is insufficient evidence with respect to the nature and scope of the proposed program, and accordingly rejects the Innovative Technologies, NGV and Measurement program expenditures at this time. Terasen may wish to bring forward projects in this program area for consideration as they become more fully developed.

2.5 Conservation Potential Review Update

The Terasen Gas April 2006 Conservation Potential Review (CPR) was a comprehensive planning document prepared for TGI to use for:

- Developing a long range energy efficiency and fuel choice strategy;
- Designing and implementing energy efficiency and fuel choice programs;
- Assessing the impact of energy efficiency and fuel choice programs on both peak and annual loads; and
- Setting annual efficiency and fuel choice targets and budgets.

(Exhibit B-1, Appendix 1, page E-1)

The 2009 CPR estimate of $0.5 million is based on the cost to perform the previous CPR, approximately $300,000, plus an allowance for the kind of work done by Habart to refine the CPR results into a DSM program. (Exhibit B-1, p. 53) The updated CPR would be received in 2010 and would form the basis for an application to the Commission for EEC funding for the period 2011 to 2014. (Exhibit B-1, p. 69) It also includes an allowance of $100,000 for cost inflation from the last CPR. (Exhibit B-2, BCUC 1.21.1)

The CPR Program is discussed at Section 4 of the Application, including an illustration of the CPR Process Flow, and a table summarising the potential annual impact identified by the 2006 CPR. The 2006 CPR identifies a gross impact [consumption reduction] by 2015/2016 of 11.615 million GJs, and a Potential Annual Impact of 10.163 million GJs after adding back 1.453 million GJs of additional load attributed to the residential fuel switching program. The gross impact number includes 1.890 million GJs for Industrial Energy Efficiency (EE). Separate programs for Industrial EE are not specifically included as part of the Application. (Exhibit B-2, pp. 44-46)

The detailed 2006 CPR report is included in the Application. (Exhibit B-2, Appendix 1)

Intervenor Positions

BCSEA-SCBC supports Terasen's proposal for approval of expenditures for an update of the CPR to form the basis for Terasen's "next tranche of EEC funding for the period 2011 to 2014." (BCSEA-SCBC Argument, p. 15)

BC Hydro supports Terasen's evidence with respect to the CPR and also the program element in the Application for additional funding for a 2009 update of the CPR. (BC Hydro Argument, p. 5)

Commission Determination

The Commission Panel considers the CPR to be an important tool for use in developing, supporting and assessing this and future EEC/DSM expenditure Applications. The Commission Panel accepts the Application's CPR update expenditure proposal.

The Commission Panel anticipates that Terasen will be able to develop a stronger and more transparent linkage between the CPR, the development of programs arising from the CPR and their proposed costs in any future EEC/DSM Applications.

2.6 The Industrial Sector

Terasen has not included energy efficiency (EE) initiatives for industrial customers in the Application. Terasen discusses its rationale for not planning for EE programs specifically for the industrial sector at Section 6.10 of its Application, Exhibit B-1, p. 78.

The CPR study conducted by Marbek Resource Consultants Ltd. and Willis Energy Services Ltd. (Marbek) concluded that:

> "The study findings confirm the existence of significant potential cost-effective natural gas efficiency improvements in B.C.'s manufacturing sector. In the "most likely" and "upper" achievable scenarios those energy efficiency improvements would provide between about 1,900 and 2,600 thousand GJ/yr. of savings in FY 2015/16. The same energy efficiency improvements would also provide reduced GHG emissions of approximately 80,000 to 112,000 tonnes per year as well as peak day load reductions of approximately 20 to 20.5 thousand GJ.
>
> Two particularly significant opportunities are identified in the study results:
>
> - Energy efficient boilers for the greenhouse and food processing facilities in the Lower Mainland.
>
> - Energy efficient kilns for sawmills and planer mills in the Interior."
>
> (Exhibit B-1, Appendix 1, p. 75)

Intervenor Positions

MEMPR provided a Letter of Comment stating: ". . .the Ministry has an interest in seeing Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. ("the Companies") expand their demand-side management activities. The Ministry notes the absence of specific demand-side measures for the industrial sector in the Application. The Companies may be missing significant conservation and efficiency gains." (MEMPR Letter of Comment, Exhibit C1-4, p. 1)

The Ministry also submitted that the Commission should include a number of determinations in its Decision with respect to the processes and timing of development of DSM measures for the manufacturing sector.

BCSEA-SCBC concurs with MEMPR's recommendation. (BCSEA-SCBC Argument, p. 16)

Terasen submits that "a cautious approach is warranted in considering delivering incentives to industrial customers at a high enough dollar level to spur participation adequate to ensure a positive TRC. Both of these options expose customers to risk. The Terasen Utilities will continue to explore opportunities for industrial DSM and will bring forward a proposal if they regard expenditures as being warranted and in the interests of customers.” (Terasen Reply, p. 17)

Commission Determination

The Commission Panel considers that the omission of an industrial sector program in Terasen’s EEC Application is a significant and unfortunate shortcoming in Terasen’s stated efforts to support the BC Energy Plan (“Energy Plan”) Policy Actions (Exhibit B-1, Appendix 6) with respect to Energy Efficiency in the industrial sector. The Commission Panel takes particular note of Terasen’s specific exclusion of EEC Policy Action 8, which addresses the development of an “Industrial Energy Efficiency Program”. (Exhibit B-1, p. 40; Energy Plan, p. 39)

The Commission Panel takes note of the MEMPR Letter of Comment, and directs Terasen to commence the planning process for the development of an industrial EE program and to file a report outlining the process contemplated and scheduling of the development plan with the Commission for review within 90 days of this Decision. The matters addressed in the report should include those raised by MEMPR in Exhibit C4-1.

3.0 ASSESSMENT CRITERIA AND ACCOUNTABILITY

Terasen believes that the benefit-cost ". . . results for the proposed EEC expenditure in this Application are under-stated, because the benefits used in the calculations include free-riders, effectively reducing the net energy savings, and exclude attribution effects, as well as excluding savings from the proposed expenditure on Joint Initiatives, Trade Relations, Conservation Education and Outreach and Innovative Technologies, Measurement and NGV. However, even with this approach, which could be considered conservative, the Total Resource Cost test result for the EEC portfolio as a whole is positive, with a ratio of 2.9., and a net financial benefit of $139.4 million. If free rider effects are excluded, as the Companies are proposing, the EEC portfolio has a TRC ratio of 3.1 and a net financial benefit of $165.1 million." (Exhibit B-1, pp. 87, 88)

3.1 Portfolio Approach

Terasen proposes a "portfolio approach" to the benefit-cost analysis which involves assessing the cost effectiveness of the EEC portfolio as a whole, "on an overall combined basis, rather than on individual initiatives or program areas." (Exhibit B-1, p. 82) Terasen proposes that the portfolio as a whole maintain a TRC ratio of 1.0 or better to allow it to include programs which, on an individual basis, may not have such a ratio in the short term, but have longer term potential to achieve the ratio. This approach would also allow Terasen to offer programs to customers in service areas which would otherwise not have sufficient customer usage to support the necessary TRC ratio. (Exhibit B-1, pp. 11-12)

<u>Intervenor Positions</u>

Mr. Plunkett indicates that judging economic performance at the portfolio level only is "problematic". (Exhibit C5-5, p. 14) He recommends that Terasen establish the cost-effectiveness of each measure and project. (Exhibit C5-5, p. 15)

Terasen states in reply that it is not proposing that economic performance be judged only at the portfolio level and that Mr. Plunkett has mischaracterized its proposal.

Terasen states that "[t]he energy efficiency and fuel switching programs would be planned and evaluated on the TRC, the RIM test, the Utility Cost ("UC") test and the Participant test, and the overall portfolio TRC test results would have to be greater than 1.0 to proceed." (Exhibit B-1, p. 83)

However, Terasen also states that it is "not proposing any thresholds with respect to the RIM test, the UC test and the Participant test. In the absence of such thresholds, [it is] not comfortable stating that an activity would proceed or not based on RIM, UC and Participant test results." Rather, Terasen proposes that "the overall portfolio level TRC must be maintained at 1.0 or greater." (Exhibit B-4, BCUC 2.19.1)

Commission Determination

The Commission Panel accepts the portfolio level approach based on achieving a portfolio TRC level, discussed below, of 1.0 or greater provided that program areas, initiatives or measures with an individual TRC of less than 1.0 are proactively designed and sufficiently support social or environmental objectives. Consequently, it is important for the components of any portfolio to be capable of analysis on an individual basis. The Commission Panel directs that Terasen include in its annual EEC Report to the Commission the results of the RIM, UC, TRC and Participant tests for each proposed DSM in its portfolio, and provide justification for continuing with any measures or groups of measures which have a TRC of less than 1.0.

Total Resource Cost Test

Terasen proposes that the benefit-cost tests be used to evaluate its programs as outlined in the "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects", which is included in Exhibit B-1 as Appendix 12 ("the California Standard Practice Manual"). (Exhibit B-1, p. 82)

The California Standard Practice Manual describes the Total Resource Cost Test as a cost-effectiveness test which "measures the net cost of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs." (Exhibit B-1, Appendix 12, p. 18)

The "benefits" portion of the TRC test is made up of the avoided supply costs, valued at their marginal cost, for periods when a load reduction results. These costs are "calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program. For fuel substitution programs, benefits include the avoided device costs and avoided supply costs for the energy, using equipment not chosen by the program participant." (Exhibit B-1, Appendix 12, p. 18)

The "costs" portion of the TRC test is made up of the program costs paid by the utility and the participants plus any increase in supply costs for periods when load is increased. This is a broad category, and includes all equipment costs, installation, operation and maintenance costs, cost of removal (less any salvage value), and administration costs, regardless of who pays, less any tax credits. For fuel substitution programs, costs also include any increase in the supply costs of the utility providing the chosen fuel. (Exhibit B-1, Appendix 12, p. 18)

The benefit-cost ratio is the ratio of discounted total program benefits to discounted total program costs over a specified period of time. A benefit-cost ratio greater than one indicates the program is beneficial, on the basis of the TRC test. (Exhibit B-1, Appendix 12, p. 19)

<u>Intervenor Positions</u>

BCOAPO prefers the "Societal test" over other cost-benefit tests which it argues "do not capture the non-economic benefits of DSM programs". (BCOAPO Argument, p. 4)

According to the California Standard Practice Manual, the "Societal test" is a variant of the TRC test. It differs in that it looks at society as a whole as opposed to the utility's service territory and includes the effects of externalities, such as environmental implications. It also excludes tax credit benefits and uses a "societal" discount rate.

Mr. Plunkett notes in his evidence that: "[i]ncluding external social and environmental benefits in calculating DSM cost-effectiveness would be to apply the societal test, not the total resource cost (TRC) test. Other jurisdictions such as Vermont and New York apply the societal test as the threshold determinant of DSM cost-effectiveness. Explicitly valuing social and environmental externalities in DSM cost-effectiveness will lead to more efficient resource allocation – and greater societal net benefits – than the economically inferior policy of pursuing a portfolio benefit/cost ratio under the TRC test of 1.0." (Exhibit C5-7, BCUC 1.5.2)

Commission Determination

The Commission Panel acknowledges the Societal test as one which addresses a broader spectrum of factors not included in the TRC test. While recognising that societal factors have significance, the Commission Panel views many of these factors as being rather subjective and difficult to measure. The Commission Panel also takes note of the DSM Regulation which will apply to Terasen as of June 01, 2009 requiring the Commission to use, in addition to any other test it considers appropriate, the TRC test in determining whether a demand-side measure is cost-effective. While the DSM Regulation is not in effect for the purposes of this Decision, the Commission Panel does consider the TRC test to be appropriate and adequate for the purposes of this Application and accepts it as such.

3.2 Free Riders

Terasen seeks certain changes to the cost-benefit analysis undertaken in respect of EEC expenditures, including a proposal to ". . . eliminate the requirement to include free riders in cost-benefit tests, as the energy and emissions reduction goals of the government are absolute goals and do not consider free ridership effects." (Exhibit B-1, p. 16)

The Application defines free riders as ". . . customers who participate in a program, but would have undertaken the same conservation actions even if the program were not offered". Terasen's proposal with respect to free riders includes two tables illustrating an estimated TRC benefit for the EEC Portfolio of $165.149 million, excluding the effects of free riders, and of $139.448 million, including the effects of free riders, a difference of $27.701 million. Terasen's discussion concludes with the view that ". . . the inclusion of the effects of free riders in the cost-benefit test for EEC programs distorts the value of EEC programs and is counter to the objectives of the energy plan." (Exhibit B-1, pp. 85-86)

Terasen responded in some detail to Information Requests concerning Free Riders, including the statements that "[f]ree riders are one of the most-debated aspects of DSM cost-benefit tests as they are challenging to establish" and "[e]stimating free rider rates . . . is more of an art than a science." (Exhibit B-2, BCUC 1.3.1)

It is Terasen's view that "it should be the outcome [energy consumption reduction] that matters, not the way in which it was achieved." (Exhibit B-1, p. 86) Terasen states: ". . . . [Government] GHG reduction goals make no mention of net-to-gross ratios – in fact they could be considered "gross" GHG reduction goals, and presumably it is gross energy savings that will be counted towards achieving those goals. It makes sense to align gross estimations of energy savings from utility DSM programs with government's gross GHG reduction goals." (Exhibit B-2, BCUC 1.3.1)

Terasen notes that "[w]hile it is possible that estimated free rider rates may be higher than forecast, it is also possible that free rider rates may be lower than forecast." (Exhibit B-2, BCUC 1.46.1)

Intervenor Positions

With respect to the free rider issue, BCSEA-SCBC's expert Mr. Plunkett states:

> "[Terasen's] proposal would depart from well-established Commission practice of accounting for savings from program free riders. This not only distorts economic assessment but is also inconsistent with resource planning, since it will overstate how much Terasen should expect to reduce energy supply requirements. It will also distort program design, especially in appliance and equipment replacement markets where the high-efficiency market penetration can change rapidly. Ignoring free ridership would tend to prevent adjustments in minimum qualifying efficiency levels due to a higher-efficiency market baseline." (Exhibit C5-5, pp.15, 16)

Mr. Plunkett's concluding recommendation included directing Terasen to modify its plan to "[d]evelop market net-to-gross ratios for programs based on estimates of free-ridership and spillover effects incorporated into program planning and design." (Exhibit C5-5, p. 23)

BCSEA-SCBC does, however, agree with Terasen that "the inclusion or exclusion of free riders from the analysis makes no practical difference in evaluating the acceptability of this specific EEC plan on an overall basis" although it notes that "failing to incorporate the free-rider factor can distort program design." (BCSEA-SCBC Argument, p. 19)

BCOAPO expresses the view that ". . . free ridership has the effect of over-crediting EEC programs. BCOAPO agrees that measuring free ridership is difficult, but this difficulty does not mean that it is appropriate to set it to zero." BCOAPO concurs with Mr. Plunkett's views with respect to the free rider issue. (BCOAPO Argument, p. 13)

Commission Determination

The Commission Panel notes the position of Terasen, and the acknowledgements of BCOAPO and BCSEA-SCBC that, in the case of the Application, the free rider issue has no immediate practical impact, as the portfolio level TCR results calculated either with or without inclusion of the free rider effect is well above the ‘break-even’ threshold of 1.0. However, the Commission Panel does consider that this issue is likely to become a factor as the DSM initiatives of Terasen become more fully developed and refined, and therefore should be addressed in this Decision.

The Commission Panel does not agree with Terasen’s position that “. . . the inclusion of the effects of free riders in the cost-benefit test for EEC programs distorts the value of EEC programs and is counter to the objectives of the energy plan.” (Exhibit B-1, pp. 85-86) The Commission Panel considers that it would be an unacceptable distortion to measure the effectiveness DSM programs by giving credit to the programs for consumption reductions which, based Terasen’s own definition (quoted above), would have taken place absent the incentive program.

The Commission Panel rejects Terasen’s proposal to exclude the free rider factor from program effectiveness (TRC) calculations.

3.3 Attribution to Regulatory Changes

Terasen submits that once a proposed regulation and implementation date for minimum efficiency standards for an appliance, building or energy system is announced by a regulating body, it be permitted to attribute savings to market transformation programs for that particular appliance, building or energy system in its cost benefit tests at that time. The proposal involves attributing the savings to the program over a five year span, with adjustment for the level of Terasen’s support for the market transformation and the level of financial contribution by others.

Terasen submits that it is reasonable to include attribution savings in a cost-benefit test, particularly in light of the newly issued DSM Regulation. The Regulation permits the Commission to include in the benefit of measures proposed a proportion of the savings resulting from the increased market share of a regulated item because of the commencement and application of a specified standard with respect to the regulated item. (Terasen Argument, p. 39; Exhibit B-1, p. 12; Exhibit B-1, p. 16)

The attribution rates proposed by the Company, for which it is seeks approval with this Application, for any such future regulation are outlined below.

Table 6
Attribution Rates

Regulation Year	Percentage of Savings Attributed to Program
1	50
2	40
3	30
4	20
5	10

Source: Exhibit B-1, p. 87

Intervenor Positions

BCSEA-SCBC's concern with respect to the attribution concept is based on Mr. Plunkett's evidence that it can distort program design. As with the free-rider factor, BCSEA-SCBC favours the use of net-to-gross ratios. (BCSEA-SCBC Argument, p. 20)

BC Hydro submits that "Terasen Utilities' position on attribution of savings from codes and standards to utility DSM programs is arbitrary and will result in an unrepresentative view of the benefits (higher or lower) associated with some programs." BC Hydro further submits that "[a]ttribution of savings from codes and standards should be evaluated on a case-by-case basis" and that "the attribution rate should reflect the level of support for market transformation", arguing that Terasen's "position on attribution goes against this approach." (BC Hydro Argument, p. 17)

BCOAPO states ". . . the DSM regulation 4(7) allows for the Commission to include a <u>proportion</u> of the benefit that, in the Commission's opinion (not the Applicant's) will increase market share only between the time that a specified standard has been announced, and the time that it commences. Any attribution beyond that will, predictably, distort program design." (BCOAPO Argument, p. 13) (emphasis in original)

In its Reply, Terasen notes that "BCOAPO and BCSEA-SCBC have made submissions on attribution of benefits. This issue is not relevant to the assessment of the proposed portfolio, as the assessment does not include any attribution of benefits. With respect to the assessment of future portfolios, the Terasen Utilities repeat and rely on the submissions made in paragraphs 109 to 111 of the Initial Submissions" (which argue for the inclusion of attribution savings.)
(Terasen Reply, p. 20)

Commission Determination

The Commission Panel notes Terasen's comment that the attribution issue is not relevant to this Application as the assessment does not include any attribution of benefits. However, as in the case of free riders, the Commission Panel does consider that this issue is likely to become a factor as the DSM initiatives of Terasen become more fully developed and refined, and therefore should be addressed in this Decision.

The Commission Panel accepts the position of BC Hydro that attribution of savings from codes and standards should be evaluated on a case-by-case basis and that the attribution rate should reflect the level of support for market transformation. The Commission Panel shares the BCSEA-SCBC's concern, as detailed in Mr. Plunkett's evidence, that the attribution concept can distort program design.

The Commission Panel rejects the Attribution to Regulatory Change proposal made in the Application and refers this issue back to Terasen to redesign and resubmit with its next annual EEC report to the Commission, giving consideration to a modified version of the Application's attribution proposal reflecting the provisions of the DSM Regulation which come into effect for Terasen on June 1, 2009. The Commission Panel directs Terasen to address, in the modified version, the matters raised by BC Hydro and BCSEA-SCBC, and also to give consideration to factors such as the length of time a particular program element has been operative at the time any applicable regulation is introduced and how compatible the program initiative is with the new regulation (e.g. if a regulation is introduced with a higher or lower threshold or standard than the program design).

3.4 Carbon Pricing

As part of the Application, Terasen seeks an order approving certain changes to the benefit-cost analysis undertaken in respect of EEC expenditures, including recognizing the impact of carbon pricing as one of the inputs to the benefit-cost tests. (Exhibit B-1, pp. 15-16)

Terasen proposes that additional customer bill savings from the implementation of the tax should be included in the benefit-cost analysis for EEC programs. Terasen proposes that the activities supported by the EEC Application will contribute to consumer education and provide consumers with tools to help them reduce the impact of the proposed carbon tax on their energy expenditures. (Exhibit B-1, p. 41)

Terasen summarises its position with respect to the carbon tax matter in Argument as follows: "The customers will also enjoy a benefit associated with reduced Carbon Tax costs. Customers that install an efficient appliance or design a more efficient building as a result of Terasen's EEC initiatives will use less gas, and will therefore pay less Carbon Tax. Therefore, the avoided Carbon

Tax was included in the participant benefits, as noted in Appendices 11A and 11B of the Application" [Terasen Argument, p. 21)

Commission Determination

The Commission Panel accepts Terasen's proposal for the carbon tax reduction as an appropriate factor to be included in computing the EEC cost-benefit analysis.

3.5 Accountability Mechanisms

Terasen summarises its proposal for accountability mechanisms as follows:

> "In this Application the Companies have recognized the need for accountability for the funds approved for EEC programs. First, any funds not spent will not be charged to the regulatory asset deferral account. Second, the Companies intend to monitor the portfolio TRC on a monthly basis, and have proposed to file an Annual EEC Report with the Commission by the end of the first quarter every year. The Report will detail program activity, expenditures, and cost-benefit results for the previous year, as well as describe program activity and provide forecasts for the upcoming year. Third, in the event that the relief sought is granted, the Companies would form and engage an EEC stakeholder group with membership representing a broad cross section of stakeholders identified in the Application. Fourth, the Companies have indicated their intention to hold annual EEC workshops with stakeholders, at which the Companies would present updates on program progress and obtain stakeholder input on new programs and refinements to existing programs. Fifth, the Companies are proposing to develop many of the programs for the commercial sector and the DSM for Affordable Housing sector in conjunction with stakeholder advisory groups." (Terasen Argument, p. 39)

<u>Intervenor Positions</u>

BCSEA-BCSC states that they: ". . . support this [funding] approach, noting that the proposed accountability mechanisms are designed to be more effective and efficient than having on-going Commission involvement in decision-making within the portfolio during the Funding Period" and "BCSEA-SCBC acknowledge and support the additional accountability mechanisms proposed by Terasen in [Terasen Argument] paragraph 112." (BCSEA-SCBC Argument, pp. 5, 20)

BCOAPO argues that, should the Application be approved, an independent audit process should be required with respect particularly to free ridership, attribution and redirection of funds. (BCOAPO Argument, p. 14)

Commission Determination

The Commission Panel accepts Terasen's accountability undertakings, and considers that, while the proposal to evaluate the EEC project using the TRC test at the Portfolio level has been accepted, TRC calculations for each program area, initiative and measure should also be included in the accountability reporting as a means of assessing the components of the Project and their ongoing effectiveness.

Commission Panel directs that the annual EEC Report include the following:

- TRC, RIM, UC, and Participant test calculations of DSM at the Program Area initiative and individual measure levels in addition to the total Portfolio level reporting. Reporting of the Residential & Commercial EE program areas should also be made at the New Construction and Retrofit levels.
- any inter and intra Program Area initiative funding transfers, with supporting rationale, and the impact of such transfers on the transferor and transferee Program areas, initiatives, and measures as the case may be.
- data for fuel switching programs should be tracked in a manner which allows for reporting types of fuels replaced by natural gas, including estimated GHG impacts.

The Commission Panel also directs Terasen to include in its annual EEC Report to the Commission a discussion of its internal data gathering, monitoring and reporting control processes. The discussion should include a description of how these processes ensure that funds expended and the statistical results of the programs implemented are completely and accurately recorded and monitored, including any related internal check and audit processes. The report should also discuss how Terasen has measured or estimated the results of the EEC expenditure initiatives.

4.0 CAPITALISATION OF INCREMENTAL EEC EXPENDITURES

Terasen's proposed EEC expenditures are summarised and discussed in Section 2.0. Terasen proposes to capitalise the approved incremental expenditures as a regulatory deferral account in the year in which the expenditures are incurred, with amortisation over 20 years commencing the year after the expenditures are made. The proposed amortisation period is addressed in Section 5.0 of this Decision.

Terasen's total EEC expenditures for 2008 to 2010 include operating and maintenance (O&M) expenditures for its previously approved DSM programs for 2008 and 2009. Terasen proposes to charge those O&M costs to operations in those years, with the balance of the total EEC expenditures being added to a new EEC deferral account. This method accounts for the impact of the legacy DSM Operating & Maintenance expenditures having been considered in the PBR and RR Extended Settlements for TGI and TGVI respectively. The reconciliation of the Total EEC expenditures and the amounts expensed and deferred is illustrated in the following table.

Table 7

Deferral Reconciliation	TGI			TGVI		
	2008	2009	2010	2008	2009	2010
Total EEC Expenditures	13,996	15,752	17,196	2,830	3,043	3,793
Expensed per Extended Settlements	1,624	1,624	-	500	500	-
Proposed Deferral Addition	12,372	14,128	17,196	2,330	2,543	3,793

Source: Exhibit B-1, pp. 49, 95, 97

Terasen points out that its proposed accounting treatment to capitalize the EEC expenditures is permitted under current Canadian Institute of Chartered Accountants (CICA) accounting standards. Terasen also notes that, effective 2011, all publicly accountable entities, including it will be required to comply with International Financial Reporting Standards (IFRS). Terasen is of the view that: “. . . the proposed financial treatment of EEC funding also meets the requirements of IFRS” and goes on to state that “[i]f, however, after further discussion and closer examination in conjunction with auditors and other utilities, the EEC funding failed to pass these [IFRS] tests, then [Terasen] will revisit the program to ensure that it continues in a fashion which maintains an alignment on interests between customers, investors and government policy.” (Exhibit B-1, pp. 81-82)

Intervenor Positions

BCSEA-SCBC comments on Terasen’s “. . . proposal to capitalize incremental EEC expenditures amortised over 20 years. BCSEA-SCBC supports this concept, including the 20 year amortisation period due to the life-expectancy of gas DSM measures.” (BCSEA-SCBC Argument, p. 17)

Commission Determination

The Commission Panel accepts Terasen’s proposal to capitalize the approved EEC expenditure to a regulatory deferral account, and to amortitse the deferral account balances over an appropriate time period. The related issues of the quantum of the expenditures approved and the appropriate amortisation period(s) for the program areas are addressed in other sections of this Decision.

5.0 AMORTISATION OF EEC EXPENDITURES

Terasen proposes to amortise its EEC expenditures, including both program, and incentive and rebate costs, over a 20 year period, based on a calculation of the 22.5 years as the weighted average measurable life of the proposed appliance and energy system installations. Terasen's weighted average calculation is based on achieving estimated volumes, mix and lives of installations for the various measures being proposed. (Exhibit B-1, p. 80, and Appendix 40.2) FortisBC and BC Hydro each use 10 year amortisation periods. (Exhibit B-2, p. 95) Terasen states: "…research failed to uncover any examples where utilities are using or proposing amortisation periods as long as 20 years" for DSM programs. (Exhibit B-2, p. 97)

Commission Determination

The Commission Panel rejects the 20 year amortisation period proposed by Terasen. The Commission panel considers the underlying forecast assumptions on which the Terasen methodology is based to be inherently uncertain, and deserving little weight. The Commission Panel does consider that a ten year amortisation period provides a reasonable balance, considering both the DSM objectives and customer impact. Terasen is directed to base its amortisation of approved EEC expenditures over periods not to exceed 10 years.

DATED at the City of Vancouver, in the Province of British Columbia, this 16th day of April 2009.

A.W. KEITH ANDERSON
COMMISSIONER

ALISON A. RHODES
COMMISSIONER

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-36-09

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

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

and

Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.
Energy Efficiency and Conservation Programs Application

BEFORE: A.W.K. Anderson, Commissioner April 16, 2009
A.A. Rhodes, Commissioner

O R D E R

WHEREAS:

A. On May 28, 2008 Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. (collectively "Terasen") filed an application for approval of various concepts and expenditures in support of an expanded energy efficiency and conservation ("EEC") strategy, and to capitalize incremental EEC expenditures by charging the expenditures to a regulatory asset deferral account and amortising the balance over 20 years (the "Application"); and

B. On June 3, 2008 the British Columbia Utilities Commission ("Commission") issued a letter requesting that interested parties register and file comments on Terasen's proposed timetable before June 11, 2008; and

C. By Order G-102-08 dated June 19, 2008, the Commission issued a Preliminary Regulatory Timetable which included two rounds of Commission Information Requests and one round of Intervenor Information Requests, and requested comments from all parties on further process for reviewing the Application; and

D. In response to Order G-102-08, the Commission received replies from Terasen and the following Intervenors: B.C. Ministry of Energy Mines and Petroleum Resources ("MEMPR"), British Columbia Hydro and Power Authority ("BC Hydro"), B.C. Sustainable Energy Association and the Sierra Club of British Columbia ("BCSEA-SCBC"), the Commercial Energy Consumers Association of British Columbia ("CEC"), B.C. Old Age Pensioners' Organization et al. ("BCOAPO"); and

E. Following its review of comments from Terasen and Intervenors, the Commission issued Letter L-39-08 dated September 8, 2008 ordering a second round of Intervenor Information Requests; and

F. By Order G-130-08 dated September 18, 2008 the Commission established a Written Hearing Process and Regulatory Timetable for its review of the Application; and

G. The Written Hearing Process concluded on December 5, 2008 with the filing of Terasen's reply submission; and

H. The Commission has reviewed and considered the evidence and submissions of Terasen and Registered Intervenors.

NOW THEREFORE pursuant to section 44.2 of the Utilities Commission Act, and subject to the specific determinations, qualifications and directions set out in the Decision issued concurrently with this Order, the Commission orders as follows:

1. The following proposed expenditures are accepted:

    (a) $31.077 million for the combined Residential Energy Efficiency and Commercial Energy Efficiency programs;

    (b) Expenditures for programs or initiatives directed at fuel switching away from fossil fuels with a higher carbon content than that of natural gas to natural gas;

    (c) $6.918 million for the Conservation Education and Outreach program;

    (d) $3 million for Joint Initiatives; and

    (e) $0.5 million for Conservation Potential Review.

2. Expenditures in the sum of $3 million for Innovative Technologies, Natural Gas Vehicles and Measurement and $1.5 million for Trade Relations are rejected.

3. The proposed portfolio approach is accepted.

4. The Total Resource Cost test is accepted as the appropriate test for cost effectiveness.

BRITISH COLUMBIA UTILITIES COMMISSION	
ORDER NUMBER	G-36-09

5. The proposal to exclude the free rider factor from benefit-cost analyses is rejected.

6. The proposal for Attribution of Regulatory Changes is rejected.

7. The proposal to include carbon tax reductions in computing benefit-cost analyses is accepted.

8. Terasen is to commence the planning process for development of an Industrial EEC program and file a report with the Commission within 90 days of the date of the Decision.

9. The proposal for accountability mechanisms is accepted and Terasen is to file an annual report on its EEC activities as described in the Commission's Decision.

10. Subject to paragraph 11 below, the proposal to capitalise the approved EEC expenditure to a regulatory deferral account and to amortise the deferral account balances is accepted.

11. The proposal to amortise EEC expenditures over a 20 year period is rejected. Terasen is directed to base its amortisation of approved EEC expenditures over periods not to exceed 10 years.

DATED at the City of Vancouver, in the Province of British Columbia, this 16th day of April 2009.

BY ORDER

A.W.K. Anderson
Commissioner

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

and

Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.
Energy Efficiency and Conservation Programs Application

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated June 3, 2008 issuing request for comments on process and proposed timetable
A-2	Letter dated June 19, 2008 issuing Order No. G-102-08 establishing the Regulatory Timetable
A-3	Letter dated June 20, 2008 issuing Commission Information Request No. 1
A-4	Letter dated July 25, 2008 issuing Commission Information Request No. 2
A-5	Letter dated September 8, 2008 establishing a Second Round of Information Requests
A-6	Letter dated September 12, 2008 issuing Commission Information Request No. 3
A-7	Letter dated September 18, 2008 and Order No. G-130-08 establishing a Written Hearing and Regulatory Timetable
A-8	Letter dated October 22, 2008 issuing Information Request #1 to BC Hydro
A-9	Letter dated October 24, 2008 filing Information Request No. 1 to BCSEA
APPLICANT DOCUMENTS	
B-1	Letter dated May 28, 2008 filing Energy Efficiency and Conservation Programs Application
B-2	Letter dated July 11, 2008 filing response to the Commission's Information Request No. 1

Exhibit No.	Description
B-2-1	**CONFIDENTIAL** - Letter dated July 11, 2008 filing response to the Commission's Information Request No. 1, Questions 9.2 and 22.1
B-3	Letter dated August 15, 2008 filing response to the Commission's Information Request No. 2
B-4	**CONFIDENTIAL** - Letter dated August 15, 2008 filing response to the Commission's Information Request No. 2
B-5	Letter dated August 15, 2008 filing response to BC Hydro's Information Request No. 1
B-6	Letter dated August 15, 2008 filing response to BCOAPO's Information Request No. 1
B-7	Letter dated August 15, 2008 filing response to BC Sustainable Energy Assoc & Sierra Club of Canada Information Request No. 1
B-8	Letter dated August 15, 2008 filing response to the Commercial Energy Consumers Association of BC's Information Request No. 1
B-9	Letter dated August 15, 2008 filing response to the Ministry of Energy, Mines & Petroleum Resources' Information Request No. 1
B-10	Letter dated August 15, 2008 filing response to the Rental Owners & Managers Society of BC's Information Request No. 1
B-11	Letter dated August 27, 2008 filing comments on submissions from Intervenor and on the further procedural process
B-12	**WITHDRAWAL ORIGINAL B-11, AMENDED AND REPOSTED** - Letter dated October 6, 2008 filing response to the Commission's Information Request No. 3
B-13	**WITHDRAWAL ORIGINAL B-12, AMENDED AND REPOSTED -** Letter dated October 6, 2008 filing response to the BCOAPO's Information Request No. 2
B-14	**WITHDRAWAL ORIGINAL B-13, AMENDED AND REPOSTED -** Letter dated October 6, 2008 filing response to the BCSEA's Information Request No. 2
B-15	Letter dated October 24, 2008 issuing Information Request No. 1 to BC Hydro and Power Authority
B-16	Letter dated October 24, 2008 issuing Information Request No. 1 to BCSEA and SCBC

Exhibit No.	Description
INTERVENOR DOCUMENTS	
C1-1	**MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES (MEMPR) –** Letter dated June 10, 2008 from Duane Chapman, Senior Regulatory Advisor, requesting participation in the proceedings
C1-2	Letter dated July 24, 2008 filing MEMPR's Information Request No. 1
C1-3	Letter dated August 27, 2008 filing comments on further procedural process
C1-4	Letter dated October 24, 2008 filing comment for consideration
C2-1	**BRITISH COLUMBIA HYDRO & POWER AUTHORITY (BC HYDRO) –** Online web registration received June 10, 2008 filing request for Intervenor status
C2-2	Letter dated June 11, 2008 filing comments on the regulatory review process and timetable
C2-3	Letter dated July 25, 2008 filing Information Request No. 1 to Terasen
C2-4	Letter dated August 27, 2008 filing comments on further procedural process
C2-5	Letter dated September, 2008 filing request for an extension for filing Intervenor Evidence
C2-6	Letter dated October 14, 2008 filing BC Hydro's Evidence
C2-7	Letter dated November 7, 2008 filing responses to the Commission's and Terasen Utilities' Information Request No. 1
C3-1	**RENTAL OWNERS AND MANAGERS SOCIETY OF BC (ROMS) –** Letter dated June 10, 2008 from Al Kemp, CEO, requesting Intervenor status
C3-2	Letter dated July 21, 2008 filing Information Request No. 1 to Terasen
C4-1	**BRITISH COLUMBIA OLD AGE PENSIONERS ORGANIZATION (BCOAPO)** - Letter dated June 11, 2008 request for Registered Intervenor status for Leigha Worth, Eugene Kung, and James Wightman of Econalysis Consulting
C4-2	Letter dated June 11, 2008 filing comments on procedural matters

Exhibit No.	Description
C4-3	Letter dated July 25, 2008 filing Information Request No. 1 to Terasen
C4-4	Letter dated August 27, 2008 filing comments on further procedural process
C4-5	Letter dated September 15, 2008 filing Information Request No. 2 to Terasen
C5-1	**BC SUSTAINABLE ENERGY ASSOCIATION (BCSEA) AND THE SIERRA CLUB OF CANADA (BRITISH COLUMBIA CHAPTER) (SCCBC)** - Letter dated June 11, 2008 request for Registered Intervenor status
C5-2	Letter dated July 25, 2008 filing Information Request No. 1 to Terasen
C5-3	Letter dated August 27, 2008 from William J. Andrews, legal counsel, filing comments on further procedural process
C5-4	Letter dated September 15, 2008 filing Information Request No. 2 to Terasen
C5-5	Letter dated October 14, 2008 filing BCSEA et al Evidence
C5-6	Letter dated October 16, 2008 filing Errata to Evidence (Exhibit C5-5)
C5-7	Letter dated November 7, 2008 filing response to the Commission's Information Request
C5-8	Letter dated November 7, 2008 filing response to Terasen's Information Request with worksheet
C6-1	**FORTISBC INC.** - Letter dated June 12, 2008 from Joyce Martin, filing request for Registered Intervenor status
C7-1	**PACIFIC NORTHERN GAS LTD. (PNG) –** Online web registration received June 18, 2008 from Craig Donohue filing request for Intervenor status
C8-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BC (CECBC)** - Letter dated June 18, 2008 from Christopher Weafer, Owen Bird, legal counsel, filing request for Registered Intervenor status and comments
C8-2	Letter dated July 25, 2008 filing Information Request No. 1 to Terasen
C8-3	Letter dated August 27, 2008 from Christopher Weafer, Owen Bird, legal counsel, filing comments on further procedural process

Exhibit No.	Description
C9-1	**DIRECT ENERGY MARKETING LIMITED (DEML)** - Online web registration dated June 25, 2008 from Chad Painchaud, filing request for Registered Intervenor status

LETTERS OF COMMENT

E-1	**CANADIAN MORTGAGE AND HOUSING CORPORATION (CMHC – SCHL)** - Letter of Comment dated June 16, 2008, faxed from Lance Jakubec, Senior Research Consultant, in support of the application
E-2	**CITY GREEN SOLUTIONS** – Letter of Comment received June 17, 2008 from Peter Sundberg, Executive Director
E-3	**LIGHT HOUSE SUSTAINABLE BUILDING CENTRE** - Letter of Comment received June 17, 2008 from Helen Goodland
E-4	**CANADIAN HOME BUILDERS' ASSOCIATION (VICTORIA) (CHBA)**- Letter of Comment received June 18, 2008 from Casey Edge, Executive Officer
E-5	**HEARTH, PATIO & BARBECUE ASSOCIATION OF CANADA (HPBAC)** - Letter of Comment received June 18, 2008 from Tony Gottschalk, Manager
E-6	**FRASER BASIN COUNCIL** – Letter of Comment received June 20, 2008 from Bob Purdy, Director, Corporate Development & Communications
E-7	**PACIFIC RESOURCE CONSERVATION SOCIETY** – Letter of Comment received June 24, 2008 from Darla Simpson, Executive Director
E-8	**CANADIAN HOME BUILDERS' ASSOCIATION (KAMLOOPS) (CHBA)** - Letter of Comment dated June 25, 2008 from Patsy Bourassa, Executive Officer
E-9	**URBAN DEVELOPMENT INSTITUTE – PACIFIC REGION (UDI) -** Letter of Comment dated July 3, 2008 from Jeff Fisher, Deputy Executive Director
E-10	**FRASER VALLEY HOME BUILDERS ASSOCIATION (FVHBA) -** Letter of Comment dated July 8, 2008 from Jan Field, Executive Officer
E-11	**CANADIAN MANUFACTURERS & EXPORTERS – BC DIVISION -** Letter of Comment dated July 5, 2008 from Craig Williams, Vice President
E-12	**NATURAL RESOURCES CANADA -** Letter of Comment dated July 9, 2008 from John Cockburn, Director, Office of Energy Efficiency

Exhibit No.	Description
E-13	**CANADIAN HOME BUILDERS ASSOCIATION OF BC (CHBA BC) -** Letter of Comment dated July 8, 2008 from M.J. Whitemarch, Chief Executive Officer
E-14	**CITY OF NANAIMO -** Letter of Comment dated July 10, 2008 from Gary Korpan, Mayor
E-15	**CITY OF VICTORIA -** Letter of Comment dated July 15, 2008 from Alan Lowe, Mayor
E-16	**CITY OF LANGFORD -** Letter of Comment dated July 22, 2008 from Rob Buchan, Clerk-Administrator
E-17	**TOWN OF LADYSMITH –** Letter of Comment dated July 24, 2008 from Mayor Robert Hutchins
E-18	**CORPORATION OF THE VILLAGE OF CUMBERLAND -** Letter of Comment dated July 18, 2008 from Christine Makarowski, Corporate Services Manager
E-19	**THE CORPORATION OF THE CITY OF NORTH VANCOUVER -** Letter of Comment dated July 29, 2008 from Darrell Mussatto, Mayor
E-20	**THE CORPORATION OF THE DISTRICT OF WEST VANCOUVER -** Letter of Comment dated July 30, 2008 from Clay Nelson, Manager
E-21	**BROOK + ASSOCIATES INC. -** Letter of Comment dated July 2, 2008 from Blair Chisholm, Planning Manager
E-22	**CITY OF POWELL RIVER -** Letter of Comment dated July 30, 2008 from Mair Claxton, City Clerk
E-23	**CORPORATION OF DELTA -** Letter of Comment dated July 30, 2008 from Lois E. Jackson, Mayor
E-24	**BC CHAMBER OF COMMERCE -** Letter of Comment dated August 11, 2008 from John R. Winter, President & CEO
E-25	**CANADIAN GAS ASSOCIATION -** Letter of Comment dated August 14, 2008 from Michael Cleland, President & CEO
E-26	**CITY OF SURREY -** Letter of Comment dated August 11, 2008 from Dianne L. Watts, Mayor
E-27	**BUSINESS COUNCIL OF BRITISH COLUMBIA -** Letter of Comment dated August 15, 2008 from Virginia Greene, President & CEO

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-194-08

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

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

and

Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.
and Terasen Gas (Whistler) Inc.
2008 Resource Plan

BEFORE: A.W.K. Anderson, Commissioner
A.A. Rhodes, Commissioner December 15, 2008

O R D E R

WHEREAS:

A. On June 27, 2008, Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. (collectively "Terasen" or "the Companies") jointly filed a consolidated 2008 Resource Plan ("Resource Plan") for acceptance by the British Columbia Utilities Commission ("Commission") in accordance with Section 44.1 of the *Utilities Commission Act*; and

B. On May 28, 2008, Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. (collectively "TGI and TGVI") filed an Energy Efficiency and Conservation Programs Application ("EEC Application"); and

C. The Resource Plan includes five-year capital plans and statements of facilities expansion, although the Companies note that they are not requesting approval of these capital plans; and

D. By Order G-120-08 the Commission established a written proceeding to review the Resource Plan; and

E. The Rental Owners and Managers Society of BC, British Columbia Hydro and Power Authority ("BC Hydro"), the Ministry of Energy Mines and Petroleum Resources ("MEMPR"), and the British Columbia Old Age Pensioners' Organization et. al. ("BCOAPO") registered as Intervenors in the proceeding; and

F. In a letter dated September 9, 2008, BC Hydro submitted that the fuel switching expenditures proposed by TGI and TGVI in the EEC Application are not in the public interest and requested Commission determinations that issues related to the EEC Application would be dealt with exclusively in the EEC Application and that a decision on the Resource Plan would be withheld until the Commission had properly considered the EEC Application; and

G. In a letter dated September 11, 2008, BCOAPO stated that it shared the concerns of BC Hydro and requested that the regulatory process for the Resource Plan be delayed until after the Commission's decision with respect to the EEC Application was released; and

H. In a letter dated September 12, 2008, Terasen submitted that the Companies supported a Commission direction confirming that EEC-related issues, including the issue of fuel switching, would be dealt with exclusively in the EEC proceeding. The Companies further submitted that such a direction would be adequate to ensure the EEC Application and the Resource Plan would be reviewed efficiently and fairly and that there was no basis to delay the regulatory timetable established for the Resource Plan; and

I. By letter L-45-08 dated September 26, 2008, the Commission directed that all issues related to the EEC Application, including fuel switching, would be dealt with exclusively in the EEC proceeding and declined to make any adjustment to the regulatory timetable for the 2008 Resource Plan; and

J. On September 30, 2008, Terasen responded to Information Requests from the Commission, BC Hydro and BCOAPO; and

K. On October 7, 2008, Terasen filed its final submissions regarding the Resource Plan; and

L. BC Hydro and BCOAPO filed their final submissions on October 14, 2008 and October 16, 2008 respectively; and

M. On October 24, 2008 Terasen filed its reply submissions; and

N. The Commission Panel determines that acceptance of the 2008 Resource Plan for filing is in the public interest, subject to the comments in the Reasons for Decision attached as Appendix A to this Order.

NOW THEREFORE the Commission Panel orders that the Resource Plan is accepted for filing by the Commission subject to the comments in the Reasons for Decision attached as Appendix A to this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of December 2008.

BY ORDER

Original signed by:

A.A. Rhodes
Commissioner

Attachment

Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.
and Terasen Gas (Whistler) Inc.
2008 Resource Plan

REASONS FOR DECISION

On June 27, 2008, Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc. (collectively "Terasen") filed their consolidated 2008 Resource Plan ("Resource Plan") with the British Columbia Utilities Commission (the "Commission"). Terasen's Resource Plan includes five-year capital plans and statements of facilities expansion, but does not include a request for approval of these capital plans. Rather, Terasen will file separate applications for Certificates of Public Convenience and Necessity, if required, for any of those projects consistent with the Commission's guidelines. The Action Plan identifies seven action items (Exhibit B-1, section 9). Only one of those action items, "Implement the new EEC program and continue research and planning for future EEC programming", requires significant new funding, and that funding is the subject of a separate application as discussed below.

Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. had previously filed, on May 28, 2008, their Energy Efficiency and Conservation Programs Application (the "EEC Application"). On June 20, 2008 by Order G-102-08 the Commission established a preliminary regulatory timetable to review the EEC Application. Subsequently, on September 18, 2008, by Order G-130-08, the Commission established a written hearing process ("EEC Proceeding") and regulatory timetable to review the EEC Application.

Order G-120-08 established a written hearing and regulatory timetable to review the Resource Plan. The Rental Owners and Managers Society of BC, British Columbia Hydro and Power Authority ("BC Hydro"), the Ministry of Energy Mines and Petroleum Resources, and the British Columbia Old Age Pensioners' Organization et. al. ("BCOAPO") registered as Intervenors in the proceeding.

On September 26, 2008, the Commission issued letter L-45-08 which stated that "…because the issues in the Resource Plan and the EEC Application are sufficiently distinct, it could approve the Resource Plan, except for EEC issues, subject to and in advance of a decision with respect to the EEC Application." (Exhibit A-3, p. 2) The Commission Panel therefore directed that all issues related to the EEC Application, including fuel switching, are to be dealt with exclusively in the EEC proceeding, and declined any adjustment to the regulatory timetable for the 2008 Resource Plan.

Consistent with the timetable established by Order G-120-08, Terasen filed responses to information requests from the Commission, BC Hydro and BCOAPO on September 30, 2008. Terasen filed its final submission on October 7, 2008. Intervenors, specifically BCOAPO and BC Hydro, filed their final submissions on October 16, 2008 and October 14, 2008, respectively. Terasen filed its reply submission on October 24, 2008.

BC Hydro's submission notes that it had filed intervenor evidence in the EEC proceeding supporting its view that the portion of the EEC expenditure targeting fuel switching from electricity to natural gas is not in the public interest at this time. BC Hydro also noted Commission letter L-45-08, which determined that Terasen's asserted regional approach to Greenhouse Gas ("GHG") emissions would be dealt with exclusively in the EEC proceeding. BC Hydro took no position on the remainder of the Resource Plan.

BCOAPO noted that Terasen's Resource Plan does not seek approval of any of the specific actions described in the Application. By way of comment BCOAPO suggested that it is "…inadvisable for a fossil fuel provider to file a long-term planning tool that ignores we now live in a country where aggressive conservation programs are or soon will be the norm and where non-GHG emitting fuel sources are preferred going forward." BCOAPO stated that it shares BC Hydro's concerns over Terasen's reliance on a solely regional analysis when evaluating GHG emissions.

BCOAPO further submitted that since Terasen filed its Resource Plan in June 2008, global economic circumstances have changed to an extent sufficient to require that the growth scenarios presented in the Resource Plan be reconsidered. BCOAPO submitted that, as opposed to the Reference Case presented in the Terasen Resource Plan, its "Low Growth" scenario is now a more appropriate reference case.

In addition, BCOAPO submitted that Terasen's reference case forecast projects an average annual growth rate of 0.7 percent due largely to increased population and economic growth, but that in response to information requests, Terasen indicated it has assumed population growth of 1.03 percent and customer growth that is 25 percent of population growth, which implies that population growth is responsible for an average annual increase of 0.258 percent. BCOAPO submitted that "…this discrepancy, combined with a likely low economic growth scenario and increased conservation efforts are cause to revisit the forecast projections and methodology." (BCOAPO Final Submission, p. 5)

BCOAPO also expressed concerns about the ability of the regional gas transmission systems in the Pacific Northwest to meet peak day demand, and commented that the Regional Infrastructure Conclusions and Recommendations do not appear to address the issue, should it arise before "the longer term".

Finally, BCOAPO expressed concerns about Terasen's Design Day Demand Methodology and, in particular, about the R-squared statistics reported for each of the separate regression equations and Terasen's multicollinear equation. BCOAPO submits that Terasen appears to have submitted "unadjusted R-squares" and requested that Terasen submit the adjusted R-squared statistics. BCOAPO also submitted that Terasen should be required to provide the variances of the parameter estimates and review the statistical methodology prior to filing its next resource plans.

In its Reply Submission, Terasen stated that the issues raised by BC Hydro are matters that must be addressed in the context of Terasen's EEC Application, and will be addressed there.

Regarding the BCOAPO comments, Terasen submitted in its Reply Submissions that it has examined GHG emissions from a provincial policy perspective as well as a regional perspective and that both of these perspectives are consistent and necessary. Terasen further argued that it is not a foregone conclusion that the low growth scenario for forecast gas demand is the most appropriate over the long term, and stated that it will continue to review and update its long-range forecast as new information becomes available "…primarily within the timeframes of its annual planning cycles." Terasen further submitted that Action Plan items within the Resource Plan address the issue of regional infrastructure capacity and identify specific solutions to alleviate the problem. Finally, Terasen submitted that it did use adjusted R-squared values, and that its current methodology is a reasonable way to estimate future design day demand.

Commission Panel Conclusions

Since Terasen is not requesting approval of any specific actions in its resource plan, it needs only to be accepted under section 44. 1 of the amended *Utilities Commission Act* RSBC 1996 c.473 ("UCA"). Section 44.1(2)(b) establishes that a long-term resource plan must include "(b) a plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures." The Resource Plan addresses that requirement of the UCA in section 4, in large measure by reference to the EEC Application, which has been ordered to be heard separately.

With regard to the issues related to fuel switching and GHG emissions, both these issues have been made part of the EEC Application and will be considered then.

The forecasting issue raised by BCOAPO is not significant now because there are no actions required by the reference case forecast presented by Terasen, and a forecast lower than the reference case implies more time before system reinforcements are required. Finally Terasen's design day forecast methodology has not been demonstrated to be incorrect in this proceeding nor has a superior method been proposed and, consequently, the Commission Panel is not prepared to direct any changes to it. However, if BCOAPO continues to have concerns about its accuracy, the Commission Panel is of the view that intervenors should be allowed the opportunity to raise the issue in the next Resource Plan filing or any other application where it is a factor, and would encourage them to submit evidence advocating an alternative approach they feel would be more appropriate.

Section 44.1(7) of the UCA states that the Commission may accept or reject a part of the public utility's plan. Because the EEC issues are to be dealt with in the proceeding to review Terasen's EEC Application, the Commission Panel accepts the Resource Plan for filing, except for Section 4 and those other parts of the Resource Plan that relate to the issue of Energy Efficiency and Conservation, including fuel switching and GHG emissions. A determination on those remaining issues will be made following the EEC Proceeding.

IN THE MATTER OF

TERASEN UTILITIES
(TERASEN GAS INC., TERASEN GAS (WHISTLER) INC.
AND TERASEN GAS (VANCOUVER ISLAND) INC.)

2010 LONG TERM RESOURCE PLAN

DECISION

February 1, 2011

Before:

D.A. Cote, Panel Chair/Commissioner
A.W.K. Anderson, Commissioner
L.A. O'Hara, Commissioner

TABLE OF CONTENTS

Page No.

EXECUTIVE SUMMARY

The Terasen Utilities filed an Application on July 15, 2010 for acceptance of the 2010 Long Term Resource Plan pursuant to section 44.1(6) of the *UCA*. The 2010 LTRP provides a high level examination of future demand and supply source expectations over the next 20 year period and outlines in broad terms the actions required over the next four year period to ensure the energy needs of customers are met over the long-term. In addition, the Application also covers the following:

- The changing British Columbia energy planning environment.
- Low and No-Carbon Initiatives.
- Energy Efficiency and Conservation-Demand Side Resources.
- Gas Supply and Regional Infrastructure Planning.

The Application was reviewed by way of a written hearing process.

In considering the Application, the Commission Panel must determine whether the requirements of section 44.1(2) of the *UCA* have been met. In addition, as required by section 44.1(8), consideration must be given to provisions related to British Columbia's energy objectives, the requirements of the *CEA*, demand side measures and public interest.

The Interveners as a group supported the Commission's acceptance of the 2010 LTRP. However, two Interveners, BCOAPO and the CEC did raise concerns with the plan with specific reference to its scope, its comprehensiveness and Terasen's lack of detail in describing how it will address the future. The Commission Panel was in agreement with these criticisms and identified them as an issue to be dealt with in the Decision. In addition, the issue of Terasen's New Initiatives and how they are most appropriately handled within a regulatory context was raised. The Panel is in agreement with the submissions of the parties and determined that this proceeding is not an appropriate venue to reach a determination on this matter. However, the Panel views the issue as sufficiently important to warrant further examination within this proceeding and direction as to how it may be addressed in the future.

The Commission Panel, after an assessment of the Application in terms of the requirements outlined in sections 44.1(2) and 44.1(8) of the *UCA* and the evidence before it, accepts the Terasen 2010 LTRP under section 44.1(6) of the *UCA* as being in the public interest.

In this Decision, the Panel comments on the quality of the 2010 LTRP and has made a number of directives concerning the preparation of future resource plans. These concern the following areas:

- The development of a longer term vision for Terasen Utilities.
- Integration of the EEC programs, New Initiatives and GHG reduction targets in demand forecasting.
- The approach to Demand forecasting given the new business environment.

An examination of Terasen's New Initiatives in terms of the regulatory questions raised, public interest concerns, competitive considerations and issues related to 'who pays' led to a Panel recommendation that the issues arising are sufficient to warrant a more formal process to address them at a future date.

1.0 INTRODUCTION

This Application is submitted by the Terasen Utilities, comprising Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. (Terasen, the Company, Terasen Utilities) for acceptance of their 2010 Long Term Resource Plan (2010 LTRP) which covers a twenty-year period through 2030.

1.1 Application

Terasen provides natural gas service to more than 935,000 residential, commercial, and industrial customers in over 125 communities throughout British Columbia. Terasen Utilities are subsidiaries of Terasen Inc., which since May 2007 has been owned by Fortis Inc.

On July 15, 2010 Terasen submitted its 2010 LTRP to the British Columbia Utilities Commission (the Commission, BCUC) for review. Terasen Utilities filed the Application in accordance with the Commission's Resource Planning Guidelines (RP Guidelines) and are seeking acceptance of the 2010 LTRP pursuant to section 44.1 of the *Utilities Commission Act* (the *Act, UCA*). The previous plan, Terasen's 2008 Resource Plan, was accepted by Commission Order G-194-08.

The 2010 LTRP examines future demand and supply resource conditions over the next 20 years and recommends actions needed during the next four years to ensure customers' energy needs are met over the long-term. It also discusses the rapidly changing energy planning environment in British Columbia, the low carbon strategies of Terasen Utilities, the new demand forecasting activities, the need to seek additional and on-going funding approvals for the Company's Energy Efficiency and Conservation (EEC) programs as well as regional infrastructure issues.

Terasen points out that the activities of a fourth company, Terasen Energy Services (TES), also provide important background in planning for the future of Terasen Utilities. It appears that beginning 2010 Terasen Utilities have begun assuming the role previously played by TES in relation to new projects. These activities include the development, construction and operation of alternative energy systems as well as setting of rates and cost recovery for those systems. (Exhibit B-1, p. 3)

1.2 Orders Sought

Terasen is seeking acceptance of the 2010 LTRP in accordance with section 44.1 of the *Act.* This section, entitled "Long-term resource and conservation planning", is reproduced in its entirety in Appendix A. Specifically, the Company requests that the Commission, after reviewing the Application, finds that carrying out the 2010 LTRP is in the public interest and accepts it accordingly pursuant to s. 44.1(6) of the *Act.* The Commission's public interest determination under s. 44.1(6) must also be guided by the criteria identified in s. 44.1(8), including the consideration of British Columbia's energy objectives, whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures, and consideration of the interests of persons in British Columbia who receive or may receive service from the public utility.

While the 2010 LTRP submission includes five-year capital plans and descriptions of facility expansions, Terasen Utilities are not seeking approval of those capital plans at this time. Terasen states that each company will file separate CPCN applications, if and as necessary, for any of those projects in accordance with the Commission's guidelines.

1.3 Regulatory Process

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

- Ministry of Energy, Mines and Petroleum Resources
- British Columbia Hydro and Power Authority
- B.C. Sustainable Energy Association and the Sierra Club of British Columbia Chapter (BCSEA)

- British Columbia Old Age Pensioners' Organization *et al.* (BCOAPO)
- Commercial Energy Consumers' Association of British Columbia (CEC)

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

Noteworthy is a question by a member of the Commission Panel during the Procedural Conference on September 21, 2010. The inquiry was about a statement made by the Company on page 186 of the Application: "Going forward, the utilities will seek approval of an overall business and regulatory model and seek CPCN approval of specific projects." (T1:7) This raised the issue of a need to better understand the view of Terasen with respect to the line separating regulatory and non-regulatory activities as the companies pursue what some might define as potentially competitive enterprises as opposed to those in a more traditional regulatory environment. By Order G-146-10 the Commission Panel requested submissions of the parties as to the need of a Second procedural Conference to address this topic. These submissions are summarized in Section 1.4.4 as they focus on the context in which the Panel has considered the 2010 LTRP.

1.4 Context

1.4.1 Resource Planning Guidelines

The Commission's mandate to direct and evaluate the resource plans of energy utilities is intended to facilitate the cost-effective delivery of secure and reliable energy services. In other words, resource planning aims at assisting the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers in the long-term. The RP Guidelines provide general guidance regarding the Commission's expectations of the process and methods for utilities to follow in developing their plans that reflect their specific circumstances and include the following key phases and/or steps:

- Identification of the planning context and the objectives of a resource plan;

- Development of a range of gross pre Demand Side Management (DSM) demand forecasts;
- Identification of supply and demand resources;
- Measurement of supply and demand resources;
- Development of multiple resource portfolios;
- Evaluation and selection of resource portfolios;
- Development of an action plan;
- Stakeholder input;
- Regulatory input;
- Consideration of government policy; and
- Regulatory review.

Further, utility specific directions may address issues regarding the elements of the resource plan or the underlying methodology. The Commission reviews resource plans in the context of the unique circumstances of the utility in question.

1.4.2 New and Alternative Energy Solutions

The Company states that energy services which integrate low and no-carbon fuel technologies with conventional energy supply provide solutions to some of the province's most pressing challenges. These challenges include increasing demand for energy, escalating energy costs, carbon emissions, job creation and economic stability. In 2010 Terasen Utilities began integrating a range of alternative energy solutions and services into their core natural gas transportation and delivery business, while at the same time increasing expenditures on energy efficiency and conservation programs. Terasen states that in the context of the 2010 LTRP, alternative energy systems are those low and no carbon technologies that provide renewable thermal energy solutions for the end user; such as geo-exchange, waste heat recovery, solar thermal and combined heat and power as well the combination of any of these types of technologies with conventional energy services in discrete and district energy systems. In addition, Terasen is pursuing new low carbon initiatives and projects which are designed to reduce Greenhouse Gas (GHG) emissions. Terasen further states that the 2010 LTRP "builds on those initial steps to transform Terasen Utilities into a complete, integrated energy provider of alternative energy solutions incorporating the reliability of conventional energy services." (Exhibit B-1, p. E-1, p. 3, pp. 9-10)

1.4.3 Terasen Description of the 2010 LTRP

The Company submits that the 2010 LTRP is "a contextual document that considers the planning environment, including B.C.'s energy objectives, input from customers and other stakeholders with insight into the future needs of the utility and the issues Terasen Utilities must continue to monitor in order to continue serving customers in the most cost-effective, safe and reliable manner." Terasen further explains that the existence of other regulatory processes directly related to resource planning have influenced the scope of what can be efficiently addressed in the 2010 LTRP. Terasen Utilities cites Annual Contracting Plans, individual gas supply contracts, the Gas Supply Mitigation Incentive Plan and applications for EEC funding as examples of these processes.

Finally, Terasen submits that because a section 44.1 filing is a higher-level planning document, there is a need for further Commission consideration of key matters described in the 2010 LTRP, including the action plan. As an example, Terasen points out it can generally only proceed with significant capital projects once a CPCN has been obtained. Similarly, the low or no-carbon initiatives will also require Commission approvals. (Terasen Final Submission, p. 2)

1.4.4 Regulatory Construct

In response to Order G-146-10 Terasen submits "the Commission's understandable desire to explore the issue of the scope of regulation in respect of these initiatives is most appropriately left to other processes to be concluded in the near future." Terasen further submits that this would allow the 2010 LTRP process to be most efficiently and effectively addressed in a written process based on the existing record. Terasen provides the following reasons for its position:

- Each of the low-carbon initiatives is unique, and therefore is not conducive to a "one size fits all" determination in a section 44.1 proceeding devoted to high-level planning.
- The initiatives are, or will be in the immediate future, the subject matter of project specific proceedings that are more conducive to addressing regulatory issues of this nature.
- This approach is consistent with the Commission-approved Negotiated Settlement Agreement (NSA) in the recent Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. 2010 and 2011 revenue requirements applications.

(Exhibit B-11, pp. 1-2)

BCOAPO submits that ultimately there will be a requirement for a holistic examination of the larger question of "what kinds of activity will properly reside with the utility, as markets, policy and rules regarding greenhouse gas-emitting hydrocarbon fuels develop" in the world of Terasen Utilities. However, BCOAPO further submits that because this Application "fails to provide a basis for the Commission to develop a meaningful handle on the fundamental questions facing it as the regulator of natural gas utilities" it would be premature to address this issue in the 2010 LTRP proceeding. (Exhibit C4-4, pp. 1-3)

BCSEA agrees with BCOAPO that the record in the 2010 LTRP proceeding is insufficient to support a high level examination of policy issues raised by the downstream, or "below the utility meter", business opportunities that Terasen Utilities are now developing. (Exhibit C3-4, pp. 1-2)

1.5 Issues Arising

Terasen is seeking acceptance of its Long Term Resource Plan which it describes as "a point in time in the Terasen Utilities high level, dynamic, and ongoing planning process." The Company notes that the process leading to this plan is not linear but iterative in nature with the final stage being the development of a four-year action plan which encompasses the implementation of the plan's recommendations and ensures resource requirements and alternatives receive ongoing assessment.

Terasen submits that the 2010 LTRP has met the requirements of the *UCA* and is in the public interest. (Terasen Final Submission, p 1-2; Exhibit B-1, p. 1)

It is Terasen's position that resource planning is an ongoing process and subject to change as it responds to new events and information. Terasen states that this freedom is a necessity if it is to take action to ensure a supply which is safe, secure and reliable. The Company further states that acceptance of the 2010 LTRP does not commit the Commission to approving cost estimates for future applications which relate to projects or programs included in this plan. Due to the likelihood of new relevant evidence being brought forward in these applications, it is not essential that the Commission approve costs in a LTRP. (Exhibit B-5, BCUC 1.1.1)

The Interveners as a group are in support of the Commission accepting the 2010 LTRP. However, two of the stakeholders, BCOAPO and the CEC have expressed concerns with the plan in terms of its scope, its comprehensiveness and the lack of specific detail in describing plans to address the future. BCOAPO is critical of the quality of the plan and questions whether it fulfills the purpose of resource planning. BCOAPO further notes that the point of resource planning is for the parties to reflect on the utilities trajectory as it relates to emerging issues. This entails dealing with what it refers to as the "Big Question" concerning the lines of business utilities pursue and how they operate in the future. Moreover, it notes that the "Long Term Plan" appears to be a short term exercise and suggests the Commission provide guidance to Terasen with respect to the preparation of future resource plans. The CEC refers to Terasen's 2010 LTRP as "essentially business as usual with a tweak" and contends that overall the plan does not go far enough in creating change over the 20 year period. The CEC also submits that the level of resource planning considering provincial GHG targets will be inadequate in setting a base for the kind of response which will be required. Further, the CEC notes the four year Action Plan which addresses low or no carbon initiatives is very short term in perspective. The CEC submits there would be little value in asking Terasen to redo its resource plan but recommends the Commission request Terasen to show substantial improvement in its next LTRP. (BCOAPO Final Submission, pp. 1-3; CEC Final Submissions, pp. 4-6)

Taking into consideration these comments and the submissions from Interveners, as well as its review of the evidence submissions of Terasen, the Commission Panel has identified a number of issues which require more detailed examination. They are as follows:

1. The Adequacy and the Quality of the 2010 LTRP

The Commission Panel views the adequacy and the quality of the 2010 LTRP as two separate issues. The adequacy of the 2010 LTRP is very much a question in determining whether it should be accepted by the Commission. Primary considerations in reaching a determination on this include requirements of section 44.1 of the *UCA*, alignment with British Columbia's energy objectives and Provincial Government policy, the RP Guidelines and any previous directions provided by the Commission with respect to future resource plans.

Aside from any decision with regard to the adequacy of the LTRP is the consideration of its level of quality. Both BCOAPO and the CEC have expressed concerns with whether the plan is sufficiently robust and complete and whether it adequately addresses the future. The Panel has similar concerns and believes that a closer examination of this issue within this Decision will lead to improvements in future LTRP applications.

2. Understanding the Meaning of Acceptance

The Commission Panel notes that the meaning of "acceptance" of the 2010 LTRP is addressed by Terasen Utilities in a number of IR responses and in its Final Submission. However, we believe there would be a benefit in providing clarity to define exactly what is meant by "acceptance." Our concern lies in ensuring that the meaning of acceptance of this plan is understood and does not "tie the hands" of Panels in reviewing future applications related to many of the initiatives considered in this Application.

3. New Initiatives

As raised previously, there is a need to address the issue of how best to handle Terasen's move into what are non-traditional and potentially competitive business lines from a regulatory perspective.

This remains an issue with the BCOAPO which in its Final Submission stated that Terasen must deal with this “Big Question” if the resource planning exercise is to be meaningful. It further notes that if the issue is left to be answered on an *ad hoc* basis through one-off applications it will mean “missing the opportunity for a careful and systematic consideration of the complex regulatory issues embedded within it.” (BCOAPO Final Submission, p. 1) While the parties have agreed that this proceeding is not an appropriate place to reach a determination on this matter, it remains an issue worthy of further examination and some direction as to how it may be addressed in the future would be constructive.

This Decision will first address whether to accept or reject in whole or in part this Application. This will be covered in Section 2.0 which will also include the Panel’s consideration of what it views “acceptance” to mean and the implications. In Section 3.0 the Panel will address what it believes to be key issues arising from the Application. This will include a discussion of the 2010 LTRP and requirements for future resource plans as well as a discussion of the issues related to Terasen’s plans to move forward with initiatives in new business areas.

2.0 COMMISSION PANEL DECISION ON THE APPLICATION

In reaching its decision as to whether to accept Terasen’s 2010 LTRP, the Panel must determine whether the requirements of section 44.1 (2) of the UCA have been met. Further, in accordance with section 44.1 (8), the Panel must consider the provisions therein related to British Columbia’s energy objectives, requirements of the *Clean Energy Act (CEA)*, demand-side measures and public interest.

Finally, the Panel must consider the 2010 LTRP within the context of the RP Guidelines and the evidence presented by the Applicant and Interveners.

In assessing the 2010 LTRP in terms of its requirements and considering the British Columbia energy objectives and policy as well as the evidence before it, the Commission Panel accepts the Terasen 2010 LTRP under section 44.1 (6) of the *UCA* as being in the public interest.

2.1 UCA Section 41.1(2) Requirements

For a long term resource plan to be accepted it must satisfy the requirements of section 41.1(2) of the *UCA*. This section is provided in Appendix A and includes the following:

- A plan to reduce demand.
- Demand estimates both before and after taking into account demand-side measures.
- A description of new or extensions to existing facilities.
- Information regarding energy purchases.
- An explanation of why either energy purchases or facility requirements are not replaced by demand side measures.
- Any other information required by the Commission.

Throughout the proceedings Terasen Utilities has referred to the 2010 LTRP as a high level planning exercise. In keeping with this, the Company has broadly outlined the issues it is concerned about and its direction over the long term. Included are demand forecasts for the next twenty year period which take into account EEC measures which have been implemented to date. (Exhibit B-5, BCUC 1.15.1.1) While Terasen has developed scenarios based on future funding levels it has provided no detail to EEC measures beyond 2011. Further, Terasen has addressed the need for additional infrastructure requirements to adequately meet demand in the future as well as its intent to move forward with a number of low or no-carbon initiatives. The 2010 LTRP makes note of these in the 8-point action plan guiding activity over the next four year period. A number of these points will result in further applications which, when filed, will provide a description of the initiatives and their impact. (Exhibit B-1, pp. 185-188)

None of the Interveners raised concern with respect to whether the requirements of section 44.1(2) have been met.

The Commission Panel is satisfied that the 2010 LTRP as filed by Terasen is adequate to meet the requirements as laid out section 44.1(2) of the *UCA*. The Panel notes that additional detail on much of what is proposed will follow in subsequent filings. Accordingly, the Panel finds there is no reason to reject Terasen 2010 LTRP on the basis of failure to meet these requirements.

2.2 Resource Planning Guidelines

The purpose and key requirements for the development of long term resource plans have been outlined previously in Section 1.4.1. The RP Guidelines were developed in 2003 and predate much of the recent legislation and changes to the *UCA*. Nonetheless they are still relevant as they provide overall direction but are not prescriptive in mandating a specific outcome to the process or specific investment decisions.

It is apparent that Terasen Utilities took some guidance in the preparation of the LTRP from the RP Guidelines. However, it is also clear the 2010 LTRP which has been filed by Terasen does not incorporate the guideline requirements fully. Most notable by their absence are the following:

- The lack of a clear outline detailing the measurement of supply-side and demand-side resources against established objectives.
- The lack of development of multiple resource portfolios for each demand forecast and related assessment of alternative resource portfolios against various gross demand forecasts.

On the positive side, Terasen has identified the planning context and objectives of the resource plan, developed four year action plans and has invited stakeholder input as outlined in the guidelines. With respect to stakeholder input, the Panel is most encouraged by Terasen’s intention to establish a Resource Plan Advisory Group as it may provide a sounding board and assist in the preparation of future plans.

The Commission Panel recognizes that the 2010 LTRP has been prepared at a high level and lacks detail. Further, Terasen admits that many of the New Initiatives included in the plan are not sufficiently developed to where they can be fully incorporated in the planning process. (Terasen Final Submission, p. 6) In addition, given the significant change and evolution of British Columbia's energy objectives and Provincial Government policy since the RP Guidelines were issued, a review and update of the guidelines is likely warranted. As a result, the Panel in considering these factors and the fact that Terasen did incorporate many elements of the RP Guidelines within its 2010 LTRP, sees no value in rejecting it based on its failure to incorporate all guideline elements.

2.3 UCA Section 41.1 (8) (a) and (b) Requirements

Section 44.1(8) of the *Act* outlines a number of provisions which must be considered by the Commission in reaching a decision as to whether to accept a long term resource plan. A discussion of each of these follows.

2.3.1 Alignment with British Columbia's Energy Objectives

The Panel finds that the Application is generally consistent with British Columbia's energy objectives as outlined in the *Clean Energy Act*. Section 2 of the *CEA* sets out British Columbia's energy objectives. Those most relevant to this proceeding 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% less than the level of those emissions in 2007,
- (ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,
- (iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,
- (iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and
- (v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;

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

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

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

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

Terasen speaks to these objectives within the 2010 LTRP. Further, the Company has provided a table summarizing how a number of initiatives it is undertaking within the plan are supported by British Columbia's energy objectives (Appendix C).

With reference to this table and its contents, the BCSEA-SCBC notes that the list of energy objectives is accurate and the 2010 LTRP is consistent with the "government's energy objectives." (BCSEA-SCBC Final Submission, p.4) The CEC indicates its desire to draw attention to British Columbia's energy objective 2 (g) which outlines reductions in GHG emissions over a 40 year timeline. The CEC's position is that Terasen's response to these objectives is confined to EEC programs and low and no-carbon initiatives which it believes "will be insufficient to see the province achieve anywhere close to the energy objectives." The CEC notes that the achievement of these GHG targets will require dramatic change over the next 20 years and, while these initiatives represent a good start, they do not provide an adequate basis for the nature and scale of activities required to contribute significantly to the energy objectives. In its view, the modest change of plus or minus 20 PJ in demand over the 20 year planning horizon will not approach the scale necessary to meet provincial objectives. Further, the CEC submits that "resource planning which does not show a full response to the scale of provincially legislated objectives is deficient." (CEC Final Submission, pp 3-5)

In Reply Terasen Utilities note that the GHG reduction targets outlined in British Columbia's energy objectives are for the province as a whole and points out that no specific sector allocations have been made. Additionally, the Company points out that the 20-year demand forecast within the 2010 LTRP does not take into account additional EEC program funding beyond that which is currently approved. It states that it plans to seek expanded EEC funding for 2012 and, as a result, the current forecast does not include the full impact of Terasen EEC programs for 2012 and beyond. (Terasen Reply, p. 4)

The Commission Panel accepts the view of Terasen Utilities with respect to the lack of sector specific allocations for GHG targets and that its demand forecasts have not included the impact of additional EEC program funding. However, we are disappointed that Terasen did not broaden its scenario options and, more importantly, provide more detailed information in preparing its alternative future scenarios. The purpose of resource planning is, in part, to create a better understanding of how the actions which are being taken in the present and over the medium term will impact the long term future. To limit the number of scenarios and details related to each reduces the usefulness of the 2010 LTRP as a tool designed to further understanding. Therefore, the Panel, while finding that the 2010 LTRP is consistent with British Columbia's energy objectives notes that the opportunity to create further understanding and perhaps debate over a key component of the plan has not been explored.

2.3.2 Requirements Under Sections 6 and 19 of the Clean Energy Act

Sections 6 and 19 of the *CEA* apply to electric utilities only and accordingly are not relevant to this Application.

2.3.3 Adequate, Cost-Effective Demand-Side Measures

Section 44.1(8) (c) requires the Commission to consider whether the LTRP demonstrates an intention to pursue adequate, cost-effective demand-side measures. The Demand-Side Measures Regulation, B.C. Reg. 326/2008 provides direction as to what is required and is listed in its entirety in Appendix D.

Terasen states that EEC programs are an integral part of its drive to meet the province's current and future energy needs and ensure the efficient use of natural gas. In April, 2009 the Commission approved funding for Terasen Utilities of $41.5 million for EEC activities through the end of 2010.

This was added to in the 2010-2011 Revenue Requirements Negotiated Settlement Agreement which increased the total funding to $72.3 million through the end of 2011. Terasen reports in its 2009 EEC Annual Report that the 2009 EEC activities were cost-effective and had a Total Resource Cost ratio of 1.2.

Terasen also reports it was conducting a Conservation Potential Review (CPR) in late 2010. The purpose of the CPR is to determine potential for EEC emissions savings from its customer base. Terasen states that it plans to submit a request for on-going funding beyond 2011 for all Terasen Utilities in its 2012 Revenue Requirement Application.

In the 2010 LTRP three EEC scenarios have been outlined. Each reflects a different funding level and resulting impact on natural gas and GHG savings. Terasen is careful to note that the scenarios have been developed using the best available data but are subject to change once the CPR results are available. Terasen explains that the funding and resulting savings amounts outlined in the Application are not targets but have been “presented to illustrate a range of EEC funding scenarios” since the full analysis required to make a formal EEC funding application is not yet complete. (Exhibit B-1, pp.115-123; Exhibit B-2, BCUC 1.38.1)

The CEC submits that a key element for EEC resource planning is the available funding for programs and the ability to plan and carry them out over multi-year time frames to achieve the market transformation being sought by Terasen Utilities. The CEC is concerned that EEC activity in the resource plan is confined to scenarios A, B and C and does not consider “the market transformation options and potentials related, particularly to markets in which Terasen is already well versed.” The CEC further submits that the 2010 LTRP is less robust than it could be if the EEC programs and activities were planned as multi-year undertakings to achieve market transformations working with governments and stakeholder associations to achieve efficiencies, reduced use and GHG reductions. Having made the above observations the CEC recommends that “the Commission accept the Terasen Long Term Resource Plan, with reservations regarding the adequacy of the EEC component of the plans.” (CEC Submission, pp. 12-13)

The Terasen 2010 LTRP provides little detail to assist in the assessment of whether the EEC measures it will undertake in the future are adequate and cost effective. This is because there is much work to be completed in advance of the formal EEC funding request which will accompany 2012 RRA to be filed later this year. The Commission Panel understands that this program is in the initial stages and limited results are available to permit a comprehensive assessment of the program to date. However, we are satisfied sufficient information has been presented to support the view that Terasen intends to pursue adequate, cost effective demand-side measures. Firstly, the Company has indicated that when the required analytical work for future EEC funding has been completed it will include measures for low income housing, rental accommodations and student education in its service area which are the key requirements for program adequacy. Secondly, while the cost effectiveness of planned EEC measures cannot be validated, the fact that only "acceptance" of the LTRP is sought will require Terasen to address this when a detailed funding request is filed. Accordingly, the Commission Panel sees no reason to reject Terasen's EEC measures due to a failure to be adequate or cost effective.

In conclusion, the Panel again notes its concern with respect to the lack of detail on EEC plans available for consideration at this time.

2.3.4 Consideration of the Interests of Persons in British Columbia

The Commission Panel considers acceptance of the 2010 LTRP to be in the interest of British Columbians who receive or may receive service from Terasen Utilities. In our view the 2010 LTRP is adequate to meet the requirements as laid out in section 44.1 (2) of the *UCA*, has adequately considered the Resource Planning Guidelines and has adequately met the provisions for consideration as laid out in section 44.1 (8) of the *Act*. In reaching this conclusion the Panel notes that acceptance of the 2010 LTRP does not constitute approval of any of the programs or initiatives addressed within the plan.

2.4 Commission Panel Observations

As noted previously, the Interveners as a group were in support of the Commission accepting the Terasen 2010 LTRP. However, in providing this support some reservations were expressed with the plan in terms of its content, scope, completeness and the level of detail. In addition, some of the Interveners had recommendations as to ways in which future long term resource plans could be improved.

The Commission Panel in accepting the 2010 LTRP would like to be clear that in its view the plan is adequate only and it agrees with the Interveners that there are many areas which could be improved upon in future resource plan submissions. In the view of the Panel, the long term resource plan is an integral part of the strategic planning process. If prepared in sufficient scope and detail it will provide a solid framework upon which to base future decision making. In providing a more robust LTRP, Terasen will provide the stakeholders the opportunity to conduct a more meaningful examination of the longer term future. In addition, the plan will be useful in supporting initiatives which flow from it.

The Panel observes that the lack of a more robust and complete LTRP may present challenges to Terasen in persuading the Commission that future applications are appropriate in the absence of longer term visions, strategies and resource requirement for the utilities. It may become increasingly difficult for the Commission to favourably consider one-off applications without the benefit of a much more comprehensive LTRP.

Section 3.1 which follows will examine the 2010 LTRP and Intervener comments in some detail and provide some recommendations with respect to future submissions. The Panel believes that these recommendations along with the stated intention of Terasen Utilities to setup a Resource Plan Advisory Group will be helpful in promoting further development of the long term planning process. In addition, in Section 3.2 the Panel will address Terasen's new business initiatives and their implications. Before proceeding we would first like to examine the matter of acceptance of the 2010 LTRP and what it means from the perspective of the Commission.

2.5 What Acceptance of the Plan Means

Terasen Utilities in its Final Submission states that it is not seeking approval of any specific initiatives in the 2010 LTRP. As previously outlined, it is the Company's intent to bring forward applications for programs, projects and initiatives outlined in the 2010 LTRP when they are completed utilizing an appropriate regulatory process. In answer to various IRs Terasen has been direct and unequivocal in stating that the acceptance of its 2010 LTRP under section 41.1(6) of the *UCA* in no way commits the Commission to approval of any program or initiative which might have been outlined in the resource planning process. In support of this, Terasen in answer to BCUC IR 1.1 states that unless the Commission were to exercise its jurisdiction under section 44.1(7) of the *UCA* "the acceptance of the LTRP does not commit the Commission to approve cost estimates in future applications which may rely on plans recommended in the LTRP..." Terasen makes similar statements in its response to BCUC IR 1.56.1 and again in BCUC IR 1.8.1. Worthy of note, however, is the caveat introduced in its response to BCUC IR 1.1 where Terasen states that acceptance of a LTRP "may be relevant and persuasive depending on the matter at issue and arbitrarily inconsistent decisions are not expected."

The Commission Panel agrees with Terasen's interpretation that acceptance of its 2010 LTRP does not commit the Commission to approve future applications once they are filed. We acknowledge the Company's efforts to keep the more strategic higher level resource planning process separate from the approval process related to programs and initiatives. In addition, for clarity purposes the Panel would like to point out our understanding of acceptance includes the following:

- The programs and initiatives outlined in the plan which seem reasonable at a high level are not sufficiently "fleshed out" to determine whether they will pass careful scrutiny when more detail is put forward and an application filed.
- A number of the new initiatives represent a new direction for Terasen and additional process may be required to determine how these new ventures will fit within the context of a regulated utility.

- After further analysis Terasen at its discretion may decide to not move forward with some initiatives outlined in the plan.

3.0 DISCUSSION OF ISSUES ARISING

3.1 Quality of the 2010 LTRP

In Section 2.0 the Commission Panel determined that acceptance of the Terasen Utilities 2010 LTRP is in the public interest. In making this determination, the Panel noted that the 2010 LTRP was in its view adequate only and there were a number of areas which could be improved upon in future resource plan submissions.

Among the Interveners, both the CEC and BCOAPO have expressed concerns with respect to the 2010 LTRP.

The CEC submits that there are numerous items which have not been factored into Terasen's capital and supply plans over the 20 year planning time frame. These result in the Company failing to undertake a broader integrated and consolidated view of the issues facing it and the initiatives it may be considering. In addition, the CEC notes that Terasen's resource plan fails to "lay sufficient ground work for the nature and scale of the activities which would be required to contribute significantly to the BC Energy Objectives." (CEC Final Submission, pp. 2-4) The CEC makes the following recommendations with respect to inclusions in future plans:

- Scenarios which include a full 20 year response to the British Columbia's energy objectives with particular regard to GHG emission reduction planning.
- Development of a practical number of scenarios related to GHG reduction, electricity and fuel pricing, fuel switching and technology development to allow Terasen to demonstrate its response to varying circumstances.
- Scenarios covering the transformation of trucking markets in BC to natural gas which would include analysis of and impact on the government's objectives for GHG reduction.
- With respect to EEC funding to address key market transformations to be considered for long term funding based on the requirements necessary to achieve the desired result.

- To broaden its resource planning to cover the full 20 year time-frame and examine alternatives to defray system upgrade costs. Referring to this the CEC submits that among the alternatives consideration should be given to targeted EEC programs where the result might be the deferral of capital expenditures due to conservation and efficiency improvements.

(CEC Final Submission, pp. 6, 8, 11, 13 and 14)

BCOAPO, in addition to raising concerns as to the need to address what it terms to be the "big question," makes the observation that given the sector is facing dramatic transformation, the 2010 LTRP projects minimal consideration of the changes which might be expected over the 20 year period covered by the plan. It is BCOAPO's position that an aim of the plan is to provide a roadmap for the evolution and direction of Terasen in future years. Aside from suggesting that Terasen Utilities may wish to consider a more robust econometric forecasting approach, BCOAPO provides little specific comment on how the plan can be improved. (BCOAPO Final Submission, pp. 1-3)

Terasen in Reply notes that the purpose and scope of the resource planning process is found in section 44.1 of the *UCA* and the Commission's Resource Planning Guidelines. Additionally, the Company submits that the focus for the 2010 LTRP is on forecasted demand and its plans to meet that demand through resource acquisition and demand-side measures. Terasen's position is that while long-term resource planning may support or provide context for planned initiatives, it does not replace the need for individual *UCA* approvals allowing them to move forward. With respect to the CEC's specific recommendations, Terasen notes that many of the requests for further analysis are in process and points to its answer to the CEC 2.1.1 as supporting this. Further, it sees no need for the econometric forecasting approach suggested by BCOAPO. On a final note Terasen Utilities support the value of scenario analysis but express the need to limit the types of analysis as a practical matter. (Terasen Reply, pp. 1-6)

Commission Panel Directives

As stated previously by the Panel, the 2010 LTRP, while accepted, is viewed as being just adequate. It falls short of our expectation that resource plans should provide a comprehensive 20 year view of a utilities trajectory and provide a strong support for programs and initiatives which will be filed with the Commission. The Panel is also disappointed that there was no attempt to describe a vision of Terasen Utilities 15-20 years from now. Adding this sense of vision completes the picture of how the actions being undertaken in the near future in combination with plans in an early stage of development will create the Terasen of tomorrow. In this way Terasen can demonstrate it is capable of meeting the challenges presented by British Columbia’s energy objectives and evolving government policy.

The foundation of any planning exercise is the analysis which is conducted to better understand the issues and challenges arising or anticipated to arise in the coming years. This is often supported by the development of well crafted scenarios outlining in detail a potential outcome or series of outcomes. The CEC has pointed out in its recommendations that Terasen would benefit from additional work in this area. Its concern is the limited number of scenarios and lack of detail for each falls short of providing a clear picture of the impact of the challenges faced by the Company and how its plans will assist in meeting these challenges. The Panel agrees with the CEC on this matter.

The Commission Panel has considered this and the balance of evidence in developing a series of directives for the next resource planning exercise. We believe these will provide some guidance in moving this process forward. Accordingly, pursuant to section 44.1(2) (g) of the *UCA*, the Panel directs the following be included in the next LTRP:

1. Terasen Utilities – A 20 Year Vision

This vision could describe what Terasen may look like in the future: its business lines, its customers, the expectations for supply and demand and the major issues it will deal with over the 20 year resource plan timeframe.

Areas which are appropriate to be covered in preparing this Vision include but are not limited to the following:

- The extent to which markets will be transformed.
- The extent to which Terasen can contribute to overall British Columbia GHG reduction objectives.
- The impact the Company's contributions to GHG reduction will have on demand.
- The importance new technology and new initiatives will have on the overall business, and their significance in terms of percentage share of its traditional business.
- An outline of what initiatives are currently planned or being considered and the status.
- The impact Terasen's efforts have, and expect to have, on meeting British Columbia's energy objectives.
- The key drivers impacting the need and timing for human, physical and other (information technology, capital etc.) resource requirements.

2. GHG Reduction Targets – EEC Planning and Impacts of New Initiatives

In respect of GHG reduction targets as impacted by EEC Planning and New Initiatives the Commission Panel directs future LTRPs to include the following:

- An analysis of the GHG targets as set out in British Columbia's energy objectives and an estimate of the portion of the required reduction that the Company believes it can reasonably attain over time.
- Greater coordination between EEC planning and the development of future resource plans. This will allow for a more detailed presentation of future EEC programs over a longer time period with expected impacts to be included as part of the LTRP process.
- Development of a limited number of scenarios detailing the impacts of varying degrees of EEC Planning measures on the demand forecast and GHG emission reductions.
- An outline of the impact of the implementation of New Initiatives on the demand forecast and GHG emission reductions.

3. New Business Environment and Approach to Demand Forecasting

Future LTRPs need to more adequately convey Terasen Utilities' understanding of the new energy and business environment, its impact on gross demand and how resource plans will be reflective of future demand growth. Accordingly, Terasen is directed to include the following in future resource plans.

- A description of the new end-use forecasting methodology, how it compares with Terasen's traditional demand forecasting approach, and reconciliation of the results of the two different approaches.
- The development of a most likely or reference case demand forecast and outline of the underlying assumptions taking into account potential legislative, regulatory or market transformation changes.
- An integration of the reference case demand forecast with the EEC scenarios and a description of the impacts.
- A detailed outline of New Initiatives and their impact on future demand and GHG reduction targets backed by rigorous analysis of potential scenarios.
- A description of the impact of each scenario on future resource requirements with consideration of the variables which could further affect these scenarios.

Finally, Terasen is directed to provide an estimate of the extent to which its proposed programs and initiatives will contribute to the achievement of British Columbia's energy objectives.

3.2 New Initiatives

In Section 1.0 the Commission Panel identified Terasens' low and no-carbon initiatives (New Initiatives) as one of the prominent issues of the 2010 LTRP and acknowledged the Interveners' ultimate concern as to what lines of businesses and regulatory constructs the Utilities will pursue in the future. The Panel also noted the agreement among parties that this proceeding is not the appropriate forum for a systematic consideration of various, complex regulatory issues embedded in these new ventures. In Section 2.0 the Commission Panel accepted the 2010 LTRP but qualified this acceptance in the case of New Initiatives by stating that "additional process may be required to determine how these new ventures will fit within the context of a regulated utility."

Terasen Utilities state that they are pursuing integrated energy solutions through three approaches:

- Integrated energy systems to encourage use of renewable and low-carbon thermal technologies for homes, businesses and institutional facilities (the built environment);
- Natural gas vehicles to promote natural gas as a low carbon transportation fuel alternative to diesel and gasoline; and
- The development of carbon neutral biomethane to displace conventional natural gas for homes, businesses and potentially in vehicles.

(Exhibit B-1, p. 52)

Terasen submits that these New Initiatives are all regulated services and "in the public interest for Terasen Utilities to pursue." Terasen acknowledges, however, that it is appropriate for the Commission to deal with the legal issue as to the extent to which New Initiatives are regulated public utility services, along with other initiative-specific considerations, in the other proceedings addressing the specific initiatives. (Terasen Argument, pp. 6-7)

A fundamental concern of the Panel is how the Commission, as the regulator of public utilities in British Columbia can oversee the evolution of a traditional utility in the new *Clean Energy Act* environment from the regulatory standpoint. The Panel concurs with the views of the Interveners, especially BCOAPO, which were highlighted in Section 1.0. If the issue of evolution of New Initiatives and the related business models is left to be answered on an *ad hoc* basis through one-off applications, as suggested by Terasen, the Commission and Interested Parties would miss the opportunity for a comprehensive and systematic consideration of complex regulatory issues embedded in the New Initiative applications. This subject is further discussed below.

<u>Regulatory Questions</u>

When New Initiatives involve a movement away from traditional utility services, issues concerning matters such as business risk, risk premiums, stranded assets, “who pays for what,” and applicability of EEC funding emerge. There may be a requirement for a template or framework within which individual projects and applications can be developed. While Terasen submits that each situation is different and therefore requires its own unique approach, the Panel believes that perhaps each ‘unique situation’ needs to be tailored within a regulatory policy framework to be determined after a more holistic review.

<u>Competitive Business vs. Regulated Public Utility</u>

As Terasen Utilities adapts to changes in the new policy environment by diversifying into new low and no-carbon business ventures the question also arises as to which activities in the “new world” belong under the umbrella of a regulated utility. Is there a risk of unfair advantage enjoyed by the utility which could undermine creation of new competitive enterprises? Is there also a risk of other unintended consequences which are not evident today but may surface in the near term as the New Initiatives evolve?

<u>Utilities Commission Act</u>

The Commission makes determinations regarding rates pursuant to sections 58 to 61 of the *UCA* and must ensure that an application or agreement places fundamentally no greater or less risk on the ratepayer at large than other rates. In this regard, the Commission Panel remains to be persuaded that the public interest is served by placing some of the costs and risks related to New Initiatives on the traditional ratepayer. An example of this challenge is the recent Biomethane Decision (Order G-194-10) which allowed Terasen move forward with the Biomethane Program on a test basis only for a two year period.

<u>British Columbia Legislation</u>

British Columbia enacted legislation designed to promote carbon reduction and the reduction of GHG's. The New Initiatives introduced by Terasen are generally in keeping with BC legislation and government policy. However, the *UCA* is silent on specific provisions for the 'who pays' question regarding carbon and GHG reduction related initiatives. Questions therefore arise as to whether rate payers are subsidising new ventures which may receive a capital contribution from EEC funding and whether such funding is any different than other EEC subsidies such as incentive payments for fuel switching, high efficiency furnace replacements etc.

<u>Future Process</u>

The Commission Panel considers that the issues raised above are beyond the scope of the 2010 LTRP and are therefore not further addressed in this Decision. However, the Panel believes that the changes being contemplated and the issues arising from them are significant enough to warrant a formal process to address them at a future date in the not too distant future.

DATED at the City of Vancouver, in the Province of British Columbia, this *First* day of February 2011.

Original signed by:

DENNIS A. COTE
PANEL CHAIR/COMMISSIONER

Original signed by:

LIISA A. O'HARA
COMMISSIONER

Original signed by:

A.W. KEITH ANDERSON
COMMISSIONER

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-14-11

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER Of
The Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.
and Terasen Gas (Whistler) Inc.
2010 Long Term Resource Plan

BEFORE: D.A. Cote, Panel Chair/Commissioner
A.W.K. Anderson Commissioner
L.A. O'Hara, Commissioner

February 1, 2011

O R D E R

WHEREAS:

A. On July 15, 2010 Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. (collectively Terasen Utilities) filed their 2010 Long Term Resource Plan (2010 LTRP; or Application) in accordance with section 44.1 of the *Utilities Commission Act* (the Act) and the British Columbia Utilities Commission's (the Commission) Resource Planning Guidelines;

B. The Application seeks acceptance of the 2010 LTRP pursuant to section 44.1(6) of the Act and, among other items, examines future demand and supply resource conditions over the next 20 years and recommends actions needed during the next four years to ensure customers' energy needs are met over the long term. Terasen Utilities does not seek approval of any particular elements of the plan;

C. On August 4, 2010, the Commission issued Order G-124-10 initiating a regulatory review process that included a Procedural Conference on September 21, 2010 and two rounds of Information Requests;

D. Following the Procedural Conference held on September 21, 2010, Order G-146-10 was issued on September 24, 2010 and established an Amended Regulatory Timetable, which provided for (a) a schedule for all Parties to make submissions on the need for a Second Procedural Conference, (b) a Default Schedule for a Written Hearing without the provision of a Second Procedural Conference and (c) an Alternative Schedule for a Written Hearing with the provision for a Second Procedural Conference;

E. Following the Commission Panels' consideration of the submissions of the Parties with respect to the need for a second Procedural Conference, Commission Order G-169 established that the regulatory review of the 2010 LTRP will proceed as a Written Hearing in accordance with the Default Schedule in the Amended Regulatory Timetable attached to Order G-146-10;

F. The Commission Panel has reviewed the Application, the evidence and the submissions and concludes that acceptance of the 2010 LTRP is in the public interest.

NOW THEREFORE the Commission orders that the 2010 LTRP is accepted. Terasen Utilities is to comply with the directives contained in the Decision, issued concurrently with this Order, when filing its next long term resource plan.

DATED at the City of Vancouver, in the Province of British Columbia, this *First* day of February 2011.

BY ORDER

Original signed by:

D.A. Cote
Panel Chair/Commissioner

Utilities Commission Act Section 44.1

Long-term resource and conservation planning

44.1 (1) [Repealed 2010-22-65.]

(2) Subject to subsection (4), a public utility must file with the commission, in the form and at the times the commission requires, a long-term resource plan including all of the following:

(a) an estimate of the demand for energy the public utility would expect to serve if the public utility does not take new demand-side measures during the period addressed by the plan;

(b) a plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures;

(c) an estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand-side measures;

(d) a description of the facilities that the public utility intends to construct or extend in order to serve the estimated demand referred to in paragraph (c);

(e) information regarding the energy purchases from other persons that the public utility intends to make in order to serve the estimated demand referred to in paragraph (c);

(f) an explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures;

(g) any other information required by the commission.

(3) The commission may exempt a public utility from the requirement to include in a long-term resource plan filed under subsection (2) any of the information referred to in paragraphs (a) to (f) of that subsection if the commission is satisfied that the information is not applicable with respect to the nature of the service provided by the public utility

(4) [Repealed 2010-22-65.]

(5) The commission may establish a process to review long-term resource plans filed under subsection (2).

(6) After reviewing a long-term resource plan filed under subsection (2), the commission must

(a) accept the plan, if the commission determines that carrying out the plan would be in the public interest, or

(b) reject the plan.

(7) The commission may accept or reject, under subsection (6), a part of a public utility's plan, and, if the commission rejects a part of a plan,

(a) the public utility may resubmit the part within a time specified by the commission, and

(b) the commission may accept or reject, under subsection (6), the part resubmitted under paragraph (a) of this subsection.

(8) In determining under subsection (6) whether to accept a long-term resource plan, the commission must consider

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

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

(c) whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures, and

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

(9) In accepting under subsection (6) a long-term resource plan, or part of a plan, the commission may do one or both of the following:

(a) order that a proposed utility plant or system, or extension of either, referred to in the accepted plan or the part is exempt from the operation of section 45 (1);

(b) order that, despite section 75, a matter the commission considers to be adequately addressed in the accepted plan or the part is to be considered as conclusively determined for the purposes of any hearing or proceeding to be conducted by the commission under this Act, other than a hearing or proceeding for the purposes of section 99.

THE REGULATORY PROCESS

ACTION	**DATE (2010)**
Intervener Registration Deadline	September 14
Procedural Conference	September 21
Commission Information Request No. 1	September 22
Intervener Information Requests No. 1	September 28
Terasen Utilities Responses to Information Requests No. 1	October 18
Commission and Intervener Information Requests No. 2	October 28
Terasen Utilities Responses to Information Requests No. 2	November 8
Submissions on the Need for a Second Procedural Conference	November 10
Terasen Utilities Final Argument	November 16
Interveners' Final Arguments	November 30
Terasen Utilities Reply	December 10

The Commission received Final Arguments from BCOAPO, BCSEA and the CEC.

Terasen Utilities addressed the Intervenor Arguments in its Reply on December 10, 2010.

2010 LONG TERM RESOURCE PLAN AND BRITISH COLUMBIA'S ENERGY OBJECTIVES

Energy Objective	2010 LTRP
To take demand-side measures and to conserve energy (section 2(b) of the CEA)	The Terasen Utilities plan to use existing EEC funding and file for approval of ongoing and expanded funding post-2012 after the necessary analytic and planning work is complete.[18]
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 (section 2(d) of the CEA)	The Terasen Utilities will be implementing an innovative technologies EEC program in late 2010 that supports energy conservation and efficiency.[19] The Terasen Utilities low- and no-carbon initiatives also support this objective.[20]
To reduce BC greenhouse gas emissions (section 2(g) of the CEA)	The Terasen's EEC programs and plans to seek approval for and implement ongoing and expanded funding would reduce GHG emissions by reducing use of natural gas.[21] The Terasen Utilities low or no-carbon initiatives would also reduce GHG emissions.[22]
To encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia (section 2(h) of the CEA)	The Terasen Utilities EEC programming currently includes high to low carbon fuel switch activities.[23] The Terasen Utilities NGV EEC program[24] and NGV service initiatives [25]would encourage the switching from diesel and gasoline to NGV, which would decrease greenhouse emissions in B.C.
To encourage communities to reduce greenhouse gas emissions and use energy efficiently (section 2(i) of the CEA)	The Terasen Utilities existing and planned EEC programs would encourage communities to reduce GHG emissions and use energy efficiently.[26] The Terasen Utilities low- and no-carbon initiatives also support this objective.[27]
To reduce waste by encouraging the use of waste heat, biogas and biomass (section 2(j) of the CEA)	The Terasen Utilities innovative technologies EEC program[28] and AES and biogas initiatives[29] would reduce waste by encouraging the use of waste heat, biogas and biomass.
To encourage economic development and the creation and retention of jobs (section 2(k) of the CEA)	The implementation of the Terasen Utilities EEC programs and capital plans would encourage development and the creation and retention of jobs.[30]
To foster the development of first nation and rural communities through the use and development of clean or renewable resources (section 2(l) of the CEA).	As part of the implementation of the Terasen Utilities EEC programs, training for skills and energy efficiency improvements for rural industry and businesses will help foster the development of First Nations and Rural Communities.[31]

Source: Terasen Utilities Final Submission, pp. 7-8

PROVINCE OF BRITISH COLUMBIA

REGULATION OF THE MINISTER OF ENERGY, MINES AND PETROLEUM RESOURCES

Ministerial Order No.

M 271

I, Richard Neufeld, Minister of Energy, Mines and Petroleum Resources, order that the attached regulation is made.

DEPOSITED
NOV 7 2008
B.C. REG. 326/2008

November 6, 2008

Date

Minister of Energy, Mines and Petroleum Resources

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section:- *Utilities Commission Act*, R.S.B.C. 1996, c. 473, s. 125.1 (4) (e)

Other (specify):-

November 3, 2008 R/1175/2008/27

DEMAND-SIDE MEASURES REGULATION

Definitions

1 In this regulation:

"Act" means the *Utilities Commission Act*;

"bulk electricity purchaser" means a public utility that purchases electricity from the authority for resale to the public utility's customers;

"community engagement program" means a program delivered by

(a) a public utility to a public entity either

(i) to increase the public entity's awareness about ways to increase energy conservation and energy efficiency or to encourage the public entity to conserve energy or use energy efficiently, or

(ii) to assist the public entity to increase the public's awareness about ways to increase energy conservation and energy efficiency or to encourage the public to conserve energy or use energy efficiently, or

(b) a public utility in cooperation with a public entity to increase the public's awareness about ways to increase energy conservation and energy efficiency or to encourage the public to conserve energy or use energy efficiently;

"education program" means an education program about energy conservation and efficiency, and includes the funding of the development of such a program;

"energy device" has the same meaning as in the *Energy Efficiency Act*;

"energy efficiency training" means training for persons who

(a) manufacture, sell or install energy-efficient products,

(b) design, construct or act as a real estate broker with respect to energy-efficient buildings,

(c) manage energy systems in buildings, or

(d) conduct energy efficiency audits;

"energy-using product" has the same meaning as in the *Energy Efficiency Act* (Canada);

"expenditure portfolio" means the class of demand-side measures that is composed of all of the demand-side measures proposed by a public utility in an expenditure schedule submitted under section 44.2 of the Act;

"low-income household" means a household whose residents receive service from the public utility and who have, in a taxation year, a before-tax annual household income equal to or less than the low-income cut off established by Statistics Canada for that year for households of that type;

"plan portfolio" means the class of demand-side measures that is composed of all of the demand-side measures proposed by a public utility in a plan submitted under section 44.1 of the Act;

"public awareness program" means a program delivered by a public utility

(a) to increase the awareness of the public, including the public utility's customers, about ways to increase energy conservation and energy efficiency or to encourage the public, including the public utility's customers, to conserve energy or use energy efficiently, or

(b) to increase participation by the public utility's customers in other demand-side measures proposed by the public utility in an expenditure portfolio or a plan portfolio

but does not include a program to increase the amount of energy sold or delivered by the public utility;

"public entity" means a local government, first nation, non-profit society incorporated under the *Society Act* or trade union;

"regulated item" means

(a) an energy device,

(b) an energy-using product,

(c) a building design, or

(d) thermal insulation;

"school" means a school regulated under the *School Act* or the *Independent School Act*;

"specified demand-side measure" means

(a) a demand-side measure referred to in section 3 (c) or (d),

(b) the funding of energy efficiency training,

(c) a community engagement program, or

(d) a technology innovation program;

"specified standard" means a standard in any of the following:

(a) the Energy Efficiency Standards Regulation, B.C. Reg. 389/93;

(b) the Energy Efficiency Regulations S.O.R./94-651;

(c) the British Columbia Building Code, if the standard promotes energy conservation or the efficient use of energy;

"technology innovation program" means a program

(a) to develop a technology, a system of technologies, a building design or an industrial facility design that is

(i) not commonly used in British Columbia, and

(ii) the use of which could directly or indirectly result in significant reductions of energy use or significantly more efficient use of energy,

(b) to do what is described in paragraph (a) and to give demonstrations to the public of any results of doing what is described in paragraph (a), or

(c) to gather information about a technology, a system of technologies, a building design or an industrial design referred to in paragraph (a).

Application

2 (1) This regulation applies only with respect to demand-side measures proposed by the authority.

(2) Effective June 1, 2009,

(a) subsection (1) is repealed, and

(b) section 3 does not apply to a public utility that is owned or operated by a local government or has fewer than 10,000 customers.

Adequacy

3 A public utility's plan portfolio is adequate for the purposes of section 44.1 (8) (c) of the Act only if the plan portfolio includes all of the following:

(a) a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;

(b) if the plan portfolio is submitted on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;

(c) an education program for students enrolled in schools in the public utility's service area,

(d) if the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area.

Cost effectiveness

4 (1) Subject to subsections (4) and (5), the commission, in determining for the purposes of section 44.1 (8) (c) or 44.2 (5) (d) of the Act the cost-effectiveness of a demand-side measure proposed in an expenditure portfolio or a plan portfolio, may compare the costs and benefits of

(a) the demand-side measure individually,

(b) the demand-side measure and other demand-side measures in the portfolio, or

(c) the portfolio as a whole.

(2) In determining whether a demand-side measure referred to in section 3 (a) is cost effective, the commission must,

(a) in addition to conducting any other analysis the commission considers appropriate, use the total resource cost test, and

(b) in using the total resource cost test, consider the benefit of the demand-side measure to be 130% of its value when determined without reference to this subsection.

(3) In determining whether a demand-side measure of a bulk electricity purchaser is cost-effective, the commission must consider the benefit of the avoided supply cost to be the authority's long-term marginal cost of acquiring new electricity to replace the electricity sold to the bulk electricity purchaser and not the bulk electricity purchaser's cost of purchasing electricity from the authority.

(4) The commission must determine the cost-effectiveness of a specified demand-side measure proposed in a plan portfolio or an expenditure portfolio by determining whether the portfolio is cost effective as a whole.

(5) If the commission is satisfied that a public awareness program proposed in a plan portfolio or an expenditure portfolio is likely to accomplish the goals set out in paragraph (a) or (b) of the definition of "public awareness program", the commission must determine the cost-effectiveness of the program by determining whether the portfolio is cost-effective as a whole.

(6) The commission may not determine that a proposed demand-side measure is not cost effective on the basis of the result obtained by using a ratepayer impact measure test to assess the demand-side measure.

(7) In considering the benefit of a demand-side measure that, in the commission's opinion, will increase the market share of a regulated item with respect to which there is a specified standard that has not yet commenced, the commission may include in the benefit a proportion of the benefit that, in the commission's opinion, will result from the commencement and application of the specified standard with respect to the regulated item.

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

and

Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.
2010 Long Term Resource Plan
Project No.

EXHIBIT LIST

Exhibit No.	**Description**
COMMISSION DOCUMENTS	
A-1	Letter dated August 4, 2010 – Appointment of Commission Panel
A-2	Letter dated August 4, 2010 – Preliminary regulatory timetable
A-3	Letter dated August 10, 2010 – Amended regulatory timetable
A-4	Letter dated September 22, 2010 – Commission Information Request No. 1
A-5	Letter dated September 24, 2010 – Reasons for Decision and Regulatory Timetable
A-6	Letter dated October 28, 2010 – Commission Information Request No. 2
A-7	Letter dated October 28, 2010 – Start Time for Second Procedural Conference
A2-1	Letter dated October 27, 2010 – BCUC Staff Submission “Retail Markets Downstream of the Utility Meter Guidelines (April 2007)”
A-8	Letter dated November 12, 2010 – Second Procedural Conference cancelled
APPLICANT DOCUMENTS TUS	
B-1	**TERASEN GAS INC., TERASEN GAS (VANCOUVER ISLAND) INC. AND TERASEN GAS (WHISTLER) INC. (TUS)** Letter dated July 15, 2010 - Application for 2010 Long Term Resource Plan
B-2	Letter dated October 18, 2010 – REVISED Filing to BC Hydro IR No. 1 to include Attachments

Exhibit No.	Description
B-3	Letter dated October 18, 2010 – TUS Filing Response to BCOAPO IR No.1
B-4	Letter dated October 18, 2010 – TUS Filing Response to BCSEA IR No.1
B-5	Letter dated October 18, 2010 – TUS Filing Response to BCUC IR No.1
B-6	Letter dated October 18, 2010 – TUS Filing Response to CEC IR No.1
B-6-1	Letter dated November 8, 2010 – TUS Filing Erratum to CEC IR1.22.4
B-7	Letter dated November 8, 2010 – TUS Filing Response to BCOAPO IR No.2
B-8	Letter dated November 8, 2010 – TUS Filing Response to BCSEA IR No.2
B-8-1	Letter dated November 8, 2010 – CONFIDENTIAL Attachment 23.1 BCSEA IR2
B-9	Letter dated November 8, 2010 – TUS Filing Response to CEC IR No.2
B-10	Letter dated November 8, 2010 – TUS Filing Response to BCUC IR No.2
B-11	Letter dated November 10, 2010 – TUS Submissions on Second Procedural Conference

INTERVENOR DOCUMENTS

C1-1	**MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES (MEMPR)** Online registration dated September 9, 2010 - Request for Intervener Status by Erik Kaye
C2-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH) –** Online registration dated September 13, 2010 - Request for Intervener Status by Joanna Sofield
C2-2	Letter dated September 28, 2010 – BCH Filing Information Request No. 1 to TUS
C3-1	**BC SUSTAINABLE ENERGY ASSOCIATION AND SIERRA CLUB OF BRITISH COLUMBIA CHAPTER (BCSEA)-** Online Registration dated September 13, 2010 - Filing Intervener Registration by William Andrews and Thomas Hackney
C3-2	Letter dated September 28, 2010 – BCSEA Filing Information Request No. 1
C3-3	Letter dated October 28, 2010 – BCSEA Filing Information Request No. 2
C3-4	Letter dated November 10, 2010 – BCSEA Submissions on Second Procedural Conference

Exhibit No.	Description
C4-1	**British Columbia Old Age Pensioners' Organization (BCOAPO) via Email** Letter Dated September 14, 2010 - Request for Intervener Status by Jim Quail and James Wightman
C4-2	Letter dated September 28, 2010 – BCOAPO Filing Information Request No. 1
C4-3	Letter dated October 28, 2010 – BCOAPO Filing Information Request No. 2
C4-4	Letter dated November 10, 2010 – BCOAPO Submissions on Second Procedural Conference
C5-1	**Commercial Energy Consumers Association of British Columbia (CEC) –** Letter dated September 20, 2010 – Request for Intervener Status by Owen Bird Law Corporation
C5-2	Letter dated September 30, 2010 – CEC Filing Information Request No. 1
C5-3	Letter dated October 28, 2010 – CEC Filing Information Request No. 2
C5-4	Letter dated November 10, 2010 – CEC Submissions on Second Procedural Conference