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

August 14, 2009

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC
V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: Terasen Gas Inc. ("Terasen Gas")
2010 and 2011 Revenue Requirements and Delivery Rates Application

Response to the Commercial Energy Consumers Association of British Columbia ("CEC") Information Request ("IR") No. 1

On June 15, 2009, Terasen Gas filed the Application as referenced above. In accordance with Commission Order No. G-89-09 setting out the Regulatory Timetable for the Application, Terasen Gas respectfully submits the attached response to CEC IR No. 1.

If there are any questions regarding the attached, please contact the undersigned.

Yours very truly,

TERASEN GAS INC.

Original signed:

Tom A. Loski

Attachment

cc (e-mail only): BCUC and Registered Parties

1. Reference: Exhibit B-1, Page 1, Executive Summary – Criteria for Investment

or $19 in 2011 . The forecasted costs underlying TGI's delivery rate proposals are reasonable and prudent. The contemplated investment in the business for 2010 and 2011 is necessary to ensure that the Company continues to be able to provide safe, reliable and cost effective service to its customers and to permit it to meet the evolving needs of its customers, stakeholders and shareholder.

1.1. Please identify the evolving needs of the shareholder, for which the Company is contemplating making investments in the 2010 and 2011 period.

Response:

There are no specific investments contained within the RRA that are solely driven by meeting the needs of the TGI shareholder. The intent of the statement contained in the preamble association with this question, "to permit it to meet the evolving needs of its customers, stakeholders, and shareholder", is to recognize that there are multiple parties that are impacted by the RRA outcomes. Specifically, the "shareholder" of TGI must be provided with an opportunity to earn a fair return on the investments it has already made and will make in the future to provide customers with safe and reliable service. Secondly, the intent of the statement was to build on the principle at the root of the PBR agreement, that customer, stakeholders, and TGI shareholder must find common ground so that energy solutions can be found that benefit the customers of TGI and TGI itself given the changing environment in which TGI operates. Thus, the expenditures outlined in the RRA are prudent and in the best interests of customers, stakeholders, and TGI shareholder.

1.2. Please identify the specific investments and the amounts of those investments which the Company is planning to make to meet the needs of its shareholder during the 2010 and 2011 period.

Response:

Please see response to CEC IR 1.1.1.

1.3. Please identify the related revenue requirement for all investments the Company is planning to make to meet the needs of its shareholder.

Response:

There are no specific investments to meet the needs of its shareholder, as stated in the response to CEC IR 1.1.1. Therefore, there is no impact on revenue requirement.

2. Reference: Exhibit B-1, Page 1, Executive Summary – PBR Ongoing Benefits

supply of natural gas, delivered safely and efficiently at a reasonable cost. The efficiencies achieved during the past six years (the "PBR Period") under the performance-based rate ("PBR") settlement agreement (the "PBR Agreement") have translated into a lower starting point for the Company's per customer Operations and Maintenance ("O&M") forecasts in 2010 (inflation adjusted) than was the case in 2003. TGI believes that it must build on that success and continue to invest in operational excellence and in delivering energy solutions to our customers.

2.1. Please provide the relevant projection year by year for each of the six years of what the TGI delivery costs would otherwise have been but for the efficiencies achieved during the last six years.

Response:

The incentive mechanisms that were included in the PBR Agreement created a framework that encouraged the Company to actively pursue and achieve efficiencies for the benefit of both customers and the Company. If there were no efficiencies achieved over the PBR Period, then the delivery costs would have been equal to the amount filed in the annual reviews, adjusted to remove the O&M efficiency factor (if there were no efficiencies achieved then O&M and capital would grow at a rate including CPI and customer growth). The delivery costs as filed for each of the years 2004 to 2009 have been recalculated to remove the efficiency factor and are presented below.

($ Millions)	2004	2005	2006	2007	2008	2009
Approximate Delivery Costs (Assuming No Efficiencies Achieved)	$ 476.4	$ 479.7	$ 498.1	$ 493.7	$ 497.8	$ 510.2

2.2. Please identify the specific efficiencies achieved during the last six years, how much was saved for each efficiency improvement achieved and whether or not the efficiency achieved is ongoing or was achieved only for a specific period of time.

Response:

Over the PBR period, TGI realized its O&M savings through a number of means including:

- Utilities Strategy Project
- Deferring activities and related costs where safe and prudent to do so
- Management of the Meter to Cash process resulting in the lowering of bad debts
- Centralized Asset Management in Distribution Services
- Department Reorganization and Streamlining

Utilities Strategy Project

At a restructuring cost of $15 million and an additional $8 million investment in information technology, annualized sustainable savings of approximately $10 million have been realized amongst the three Terasen Gas utilities with TGI's share at approximately $8 million per year. The USP initiative created the common platform (management, work processes, IT systems) that is fundamental to how the utilities are able to operate efficiently today.

Prudently Deferring Activities

As outlined in the response to BCUC IR 1.75.1 and BCUC IR 1.77.1, approximately $1.4 million of O&M costs have been deferred. Excluding the amount related to the building maintenance which has varying frequencies, these expenditures can no longer be deferred.

Management of the Meter to Cash Process – Lower Bad Debts

Changes in the bad debt management processes coupled with a stronger economy have led to lower bad debt experience rates over the term of the PBR Period. Bad debts are approximately $1 million per year lower during the PBR Period than that observed pre-PBR. The forecasted level of bad debt in 2010 and 2011 reflects this lower amount.

Centralized Asset Management in Distribution Services

The implementation of a centralized Asset Management group in Distribution Services has enabled the analysis of equipment and asset performance. This has resulted in changes in maintenance processes and requirements that have improved the effectiveness of the

maintenance resource investments and in some cases, associated reduction in certain specified maintenance frequencies with associated savings passed on to our customers and shareholders. Examples of assets with changes to maintenance frequencies include: station overhauls and meter set operational checks with specific regulator types.

Centralized analysis of equipment and asset performance has enabled the evaluation and prioritization of requested un-scheduled maintenance with associated savings. Examples of unscheduled maintenance activities evaluated, prioritized and deferred include: painting of bridge and aerial crossings, repair of non-critical valves and limited right of way clearing. Please refer to the response to BCUC IR 1.75.1 for a listing of related expenditures deferred (items 1 – 4) which is also included as part of section "Prudently Deferring Activities" above.

To enable a centralized approach to asset management, an investment in the SAP Preventive Maintenance module was made prior the PBR period.

Department Reorganization and Streamlining

TGI's departments are reorganized and streamlined as required in order to effectively carry out its business activities and enhance its ability to perform for the benefit of ratepayers and the shareholder. The specific dollar value of any investments required and efficiencies realized are not individually tracked but is reflected in the overall savings that TGI has realized during the PBR Period.

2.3. Please provide TGI's view as to whether or not it would be prepared to be held accountable to the same PBR parameters through the 2010 and 2011 period.

Response:

Please see the response to CEC IR 1.11.3.

2.4. Please provide an explanation with regard to how each efficiency improvement achieved was achieved and describe what investments were made to facilitate achieving these efficiencies

Response:

Please refer to the response to CEC IR 1.2.2.

2.5. Do the 2010 and 2011 periods anticipate any further achievement of efficiencies or just retention of those achieved during the six year PBR period?

Response:

Although Terasen Gas intends to continue to strive to achieve efficiencies in pursuit of continuous improvement and Operational Excellence into the future, it does not anticipate achieving any further significant efficiencies during the 2010 and 2011 periods. Many large scale efficiencies have been realized (i.e. USP Project) and are imbedded today in TGI's cost structure for the benefit of customers into the future.

Instead, TGI is now faced with escalating cost pressures as it responds to the changing competitive environment and the evolving needs of its customers and stakeholders.

3. Reference: Exhibit B-1, Page 1, Executive Summary – Accounting Changes

The primary drivers of the requested rate increases for 2010 and 2011 are the significant changes taking place in the external operating environment. The single largest contributor to the requested rate increase, for instance, is accounting changes associated with the adoption of new accounting standards applicable to TGI. But for the accounting changes, the revenue requirement would have indicated a rate decrease for 2010 and a small increase for 2011. TGI must respond to the accounting changes. Our

3.1. Please confirm that the all the accounting changes being referred to in the executive summary are identified and covered in Appendix H.

Response:

The accounting changes that are referred to in the executive summary encompass all of the accounting changes reflected in the Revenue Requirements for 2010 and 2011 that are driven by changes to IFRS and Canadian GAAP. The major impacts of these changes on revenue requirements are discussed in Part III, Section C, Tab 11 of the Application, and summarized in Table C-11-1. The last two items in Table C-11-1 refer to policy changes other than IFRS and Canadian GAAP. The reports and studies that support the changes are provided in Appendix H as follows:

H-1 International Financial Reporting Standards (IFRS): A Summary of Anticipated Impacts of Transition to IFRS on Rate Regulated Utilities in British Columbia

H-2 Depreciation Study

H-3 2010/11 Overhead Capitalization Methodology Review

H-4 Shared Services Cost Allocation Review

H-5 Corporate Services Review

3.2. Please prepare a schedule listing the specific accounting change on the left and for each accounting change on the left provide in columns to the right for 2010 and for 2011 the change in revenue requirements precipitated by the change relative to the previous accounting methodology employed by the Company and used for the purpose of establishing TGI rates.

Response:

Please see Table C-11-1 on page 474 of the Application.

3.3. Please ensure that the above table breaks down the accounting changes to each specific accounting rule that is being changed.

Response:

Please see the reference column of Table C-11-1 on page 474 (revised July 8, 2009) of the Application.

3.4. Where the accounting change does not involve an accounting rule change please identify the specific driver of the accounting change such as change.

Response:

The changes that are not specific to IFRS or Canadian GAAP are the update of the Shared Services charges between TGI and TGVI/TGW, and the update of the Corporate Services charges from Terasen Inc. to TGI. These charges were last reviewed by the Commission in 2003, and formed part of the base O&M to which the formula has been applied throughout the term of the PBR. Now that TGI is rebasing its O&M to forecast from formula, the amount of shared and corporate services costs included in O&M needs to be updated accordingly. These amounts are normally reviewed at each Revenue Requirement proceeding. For a review of the drivers behind the changes please refer to Page 495 of the Application for Shared Services, and Page 501 of the Application for Corporate Services.

3.5. Please identify specifically why TGI must respond to accounting changes and specifically what response TGI must make.

Response:

Canadian GAAP for publicly accountable entities will be replaced with IFRS for fiscal 2011. Terasen Gas has debentures listed and traded publicly and as such is considered a publicly accountable entity. Terasen Gas is required to adopt IFRS for 2011 with comparative results provided for 2010, which effectively results in 2010 adoption since all 2010 impacts will be reflected in the Company's accounting records. If Terasen Gas did not adopt IFRS then it would be in default of a number of agreements as it would not be able to obtain an audit opinion from a recognized auditing firm and would be in breach of a number of financial agreements including credit and debenture agreements. Also, it would be placed on the default issuers list with the British Columbia Securities Commission.

3.6. Please provide TGI's views as to whether or not the BCUC is bound to follow and use whatever TGI's decisions and choices are with respect to how TGI responds to accounting changes for the purpose of determining rates for TGI.

Response:

Past court decisions have affirmed the role of the management of public utilities to manage the business of the public utility, which includes the ability to make appropriate accounting decisions. The Commission's core role, by contrast, is to establish just and reasonable rates for the public utilities it regulates. In arriving at just and reasonable rates, the Commission has considerable latitude to account for various factors. As part of this discretion, the Commission has the ability to set rates on a different basis from the accounting decisions made by a public utility if it reasonably concludes that the accounting decisions made by the public utility result in unjust and unreasonable rates. TGI believes, however, that accounting decisions or policies adopted by the Company in accordance with the applicable financial accounting standards will not generally result, in and of themselves, in unjust and unreasonable rates.

TGI and other public utilities in BC believe it is important, and in the interest of customers, to continue to maintain the historical connection between the accounting policies used in external financial statements and their regulatory accounting treatment. This harmonization is achieved through the use of GAAP for both purposes, whether that GAAP is Canadian or International. Costs will be reduced in the long run, since a single set of financial statements will serve to:

1. Reduce the costly burden of reconciling and of providing additional material to enable understanding of the economic effects of regulation;
2. Reduce audit and verification costs for two sets of books;

3. Improve transparency by harmonizing results, and achieve a better balance for all stakeholders (similar decisions based on similar information).

TGI believes that the decisions it has made, and which are reflected in this Application, are all in accordance with IFRS and that the rates proposed are just and reasonable rates. As such, TGI believes that there is no justification to depart from these policy decisions in this case.

4. Reference: Exhibit B-2, Page 2, Executive Summary – Government Policy

alternative (and renewable) energy sources. Provincial policy and recent amendments to the Utilities Commission Act (the "Act") have given utilities such as Terasen Gas the responsibility for implementing the Provincial government's energy objectives. In fact, energy policy calls upon utilities to play an integral role in doing this very thing. The implications of these policies for Terasen Gas are profound, and TGI is compelled to respond.

"government's energy objectives"

(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;

(Extract from UCA Definitions)

4.1. When referencing Provincial government energy objectives TGI uses policy directions from the 2007 Energy Plan to provide examples of the profound implications. Please provide TGI's view with respect to the role of the UCA and the role of the 2007 Energy Plan as a source for defining the TGI responsibility for implementing the Provincial government's energy objectives.

Response:

Provincial policy as stated in the Energy Plan applies to TGI in a somewhat different manner than the provisions of the UCA.

TGI considers the Energy Plan to be an expression of Provincial Government policy. In and of itself, the Energy Plan is not binding on the Commission. However, TGI believes that it is in the public interest for regulation of public utilities to account for Provincial energy policy, particularly the Energy Plan. This is consistent with prior decisions of the Commission. In *Re: British Columbia Hydro and Power Authority 2007 Rate Design Application Phase I* (Decision, October 26, 2007), the Commission commended BC Hydro's decision to introduce an inclining block residential rate structure because it was "in accordance with Policy Action 4 of the 2007 Energy Plan." In its recent decision *Re: British Columbia Hydro and Power Authority and an Application for an Approval of the 2008 Long Term Acquisition Plan* (Decision, July 27, 2009, at pp. 44-45), the Commission relied upon the 2007 Energy Plan as a "contextual aid" when interpreting the Government's energy directives, finding that,

> *"BC Hydro has failed to recognize the 2007 Energy Plan reference to "the long lead time and implementation risks associated with new projects and the challenges of forecasting future needs," and accordingly has failed to adequately address the self-sufficiency obligation established by SD 10 in its 2008 LTAP".*

There are numerous instances in the 2007 Energy Plan where the Province expresses its support for alternative energy solutions. A notable example is the following statement on Page of 22 of the Energy Plan (Application, Appendix C-2):

> *"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."*

The UCA is the legislation that defines the scope of the Commission's jurisdiction regarding the regulation of public utilities. The UCA was amended in 2008 to require the Commission to

consider "government's energy objectives" in the context of three types of applications: CPCN's, approval of expenditure schedules under section 44.2, and approval of resource plans under section 44.1. By virtue of this legislative requirement, the Commission must consider "government's energy objectives". The Commission retains discretion as to how "government's energy objectives" should be applied, but it must consider them in coming to a decision. The UCA does not specifically direct public utilities to pursue measures consistent with "government's energy objectives", but this is implicit in the fact that the Commission must apply the objectives when regulating the public utilities.

In the Commission's recent decision in *Re British Columbia Hydro and Power Authority and an Application for an Approval of the 2008 Long Term Acquisition Plan* (Decision, July 27, 2009, at p. 11), the Commission referenced its "obligation to consider the government's energy objectives."

TGI's proposed EEC funding is advanced under section 44.2, the expenditure schedule section. In considering this proposal, the Commission must consider, as it did when deciding TGI's 2008-2010 Energy Efficiency and Conservation Application, "government's energy objectives" (i) "to encourage public utilities to take demand-side measures"; and (ii) "to encourage public utilities to reduce greenhouse gas emissions". The EEC portfolio outlined in the Application are "demand side measures" that will result in the reduction of gas consumption and greenhouse gas emissions.

With respect to the alternative energy solutions, in the normal course TGI would apply for a CPCN for the construction and operation of facilities such as a district energy system. In considering that application, the Commission would have to consider "government's energy objective" "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 "to encourage public utilities to reduce greenhouse gas emissions". TGI believes that the pursuit of alternative energy solutions is consistent with these objectives because it promotes the use of clean or renewable sources of energy and accordingly will reduce greenhouse gas emissions. In this Application, TGI is proposing economic tests as a means of simplifying the regulatory process and encouraging administrative efficiency; however, the same "government's energy objectives" ought logically to be applied in considering those economic tests as would be the case under the normal regulatory process.

As described in the Application, TGI believes that the pursuit of alternative energy solutions, in conjunction with natural gas, is in the public interest. TGI is well positioned to deliver alternative energy solutions due to its interaction with customers.

4.2. How does TGI interpret the UCA definition of "government's energy objectives' with respect to the operative verb "to encourage", which is used in each of the six objectives listed?

Response:

TGI considers the term "encourage" to mean that the Province's interest is ultimately to involve public utilities in promoting, for example, energy efficiency by means of providing "demand-side measures" and promoting the use of "innovative energy technologies…that support energy conservation or efficiency or the use of clean or renewable sources of energy". In other words, the inclusion of such provisions in the UCA constitutes express recognition of the key role public utilities should play in delivering energy efficiency and conservation programs and alternative energy solutions. The UCA imposes an obligation on the Commission in discharging its responsibilities under the Act to consider the objectives of energy efficiency and promotion of renewable and clean energy, and the unique role public utilities can play in advancing those objectives, when such measures are put forward by public utilities like TGI.

While the obligation to consider "government's energy objectives" is on the Commission and not on the utility itself, the legislation also includes provisions intended to spur public utilities to pursue, for instance, demand-side measures. There is a requirement on public utilities in section 44.1 to justify in a long-term resource plan "why the demand for energy to be served by" the facilities contemplated "…are not planned to be replaced by demand-side measures". The legislature had previously amended the UCA to add section 60(1)(b), which requires the Commission to have due regard in setting rates that a public utility is provided "a fair and reasonable return on any expenditure made by it to reduce energy demands." As explained on pages 35-36 of the Application, 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.

As outlined in the 2007 Energy Plan, utilities in BC have a role to play in helping fulfill the government's energy objectives. 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) of the Energy Plan are examples that give specific direction to utilities on the role that they need to play in helping government achieve it's energy and climate change objectives.

TGI believes that the legislative and policy framework supporting energy efficiency and conservation and alternative energy solutions justifies the measures proposed in this Application.

4.3. How does TGI interpret the UCA requirement on the Commission with respect to "considering" the government's objectives as it is used in Sections 44.1 (8), 44.2 (5), 46 (3.1), 71 (2.1) & 71 (2.5)?

Response:

As described in the response to CEC IR 1.4.1, the Commission retains discretion as to how "government's energy objectives" should be applied, but it must consider them in coming to a decision under the sections to which the definition applies (sections 44.1, 44.2 and 45).

4.4. What does TGI believe the Commission is required to do with respect to "government's energy objectives" in regard to establishing revenue requirements and rates?

Response:

The definition of "government's energy objectives" does not specifically apply to the setting of rates under sections 59-61 of the UCA. However, as described in the Application (see, for instance, pages 27-47), developments in government policy generally in respect of greenhouse gas emissions and energy efficiency have necessitated a response from TGI. This Revenue Requirement Application includes costs that are driven by these policy developments. Under section 60 of the UCA, the Commission is given wide discretion to consider all matters it considers "proper and relevant." As discussed in the Application and in the response to CEC IR 1.4.1, both the Energy Plan and 2008 amendments to the UCA are founded upon energy efficiency and conservation and the promotion of alternative energy. Thus, TGI believes that the Commission, in establishing just and reasonable rates for TGI for 2010 and 2011, should appropriately reflect the legitimate costs forecasted by TGI to be incurred in responding to government policy.

4.5. In what way do each of the six 'government's energy objectives" apply to TGI and how does TGI believe that the Commission could or should consider them in determining revenue requirements and rates as a consequence of this application.

Response:

Please see the responses to CEC IR 1.4.1 and CEC IR 1.4.5.

5. Reference: Exhibit B-1, Page 3, Executive Summary – Communities as a Focus for Energy Planning

that can be used as an alternative to, or in conjunction with, natural gas. Communities are becoming more engaged in energy planning and Terasen Gas must invest to ensure that it continues to meet these evolving expectations. This Application outlines a number of key areas of investment for 2010 and 2011.

5.1. Has Terasen surveyed BC Communities to determine what their interests are or could be in energy planning and if so could that information be provided?

Response:

TGI has not directly undertaken a formal survey of municipalities, however we engage daily with our community partners in a number of ways: through our Community Relations group, our day to day operations, through our Sales and Marketing efforts, and through our participation in the Community Energy Association. Community interests in energy planning are a recurring theme in all of our contact, and we are being asked what we can do to help with energy planning and GHG reductions. A large percentage of communities (174 local governments as at March 31, 2009) have signed on to the Climate Action Charter, and have committed to including an energy plan in the next version of their Official Community Plan (OCP.) From our contact with BC Communities we know that they are interested in both energy planning as well as Alternative Energy. The Community Energy Association also issued a report dated March 17, 2009 entitled "BC Local Government Survey: District Energy, Renewable energy and Energy Planning Report on Results". Please see Attachment 5.1 for a copy of the Report, which can also be viewed via the following link: http://www.communityenergy.bc.ca/resources-introduction/2008-energy-survey-report . The report indicates that in 2008, 55% were taking steps towards developing a community energy/GHG reduction plan and 66% had hired or planned to hire an energy/GHG planner (please also see the response to BCUC IR 1.23.1.1).

5.2. What does Terasen believe that local BC Communities can or may do in the future with regard to energy planning?

Response:

We believe the comprehensive energy planning will be integral to future Official Community Plans (OCP). Some communities will and have developed initiatives supported through bylaws to ensure compliance to energy plan components of the OCP. TGI believes that communities

will make significant progress toward meeting their commitments under the Climate Action Charter. Communities will look for energy experts, local utilities especially, to support them in these efforts. TGI's proposals in this Revenue Requirement Application are intended to position TGI as a provider of broader energy solutions, including natural gas. As described in TGI's response to CEC IR 1.5.1, TGI has already held discussions with municipalities regarding their needs in this regard.

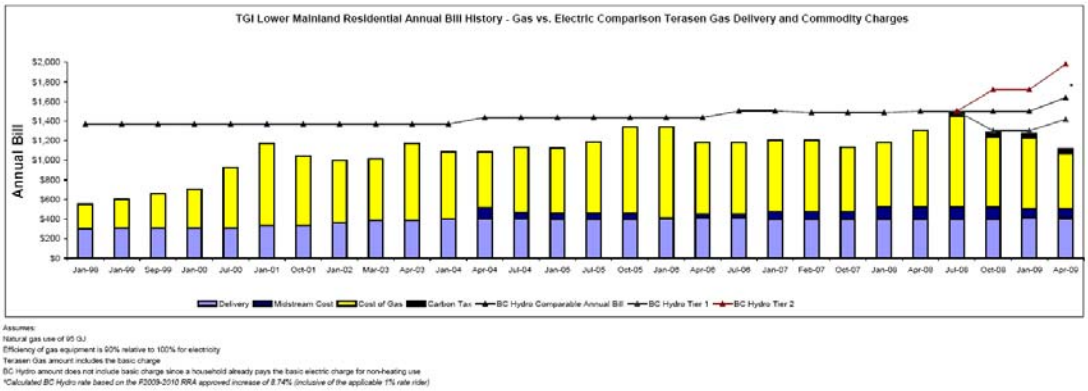
5.3. Does Terasen believe that its business risks and financial risks will be reduced if it is enabled to engage in innovative energy planning and implementation with local BC Communities?

Response:

As this is a long-term issue and engaging communities is only one component of TGI's overall strategy, it is difficult to say at this time that this one activity will reduce TGI's business and financial risks.

6. Reference: Exhibit B-1, Page 3, Executive Summary – Competitive Position versus Electricity

TGI's competitive position in B.C. continues to decline with increases in natural gas prices and the gradual erosion of the cost advantage of natural gas over electricity. This is occurring, despite natural gas market prices improving relative to other energy commodities (such as oil) in the North American marketplace. Terasen Gas faces challenges in the B.C. marketplace due to the differing nature of how natural gas and electricity prices are set into customer rates. These factors reduce new customer



Assumes:
Natural gas use of 95 GJ
Efficiency of gas equipment is 93% relative to 100% for electricity
Terasen Gas amount includes the basic charge
BC Hydro amount does not include basic charge since a household already pays the basic electric charge for non-heating use
*Calculated BC Hydro rate based on the F2009-2010 RRA approved increase of 8.74% (inclusive of the applicable 1% rate rider)

Appendix C-26

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]

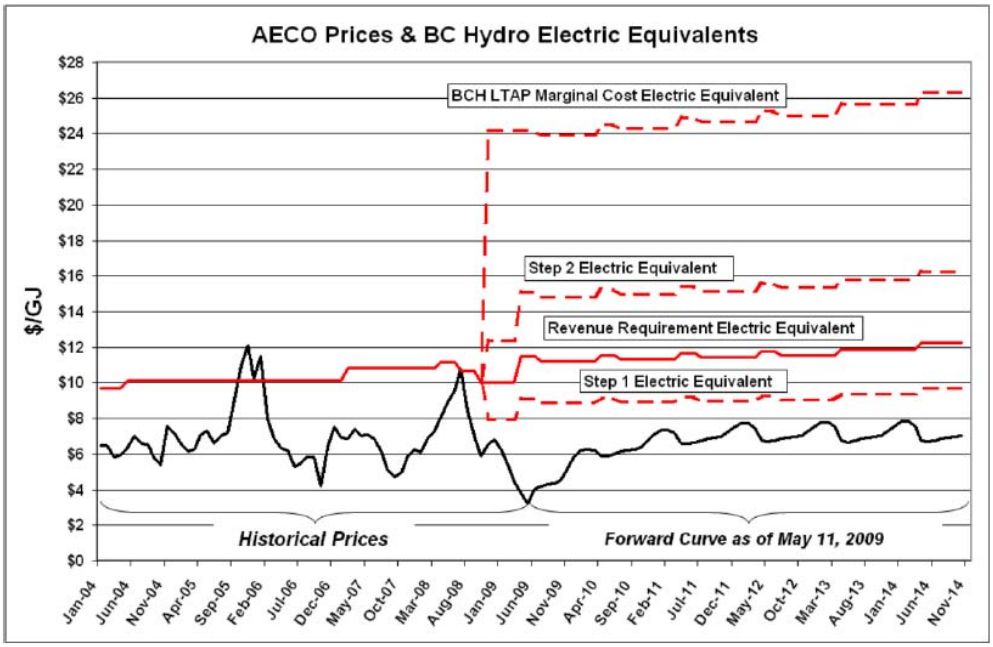
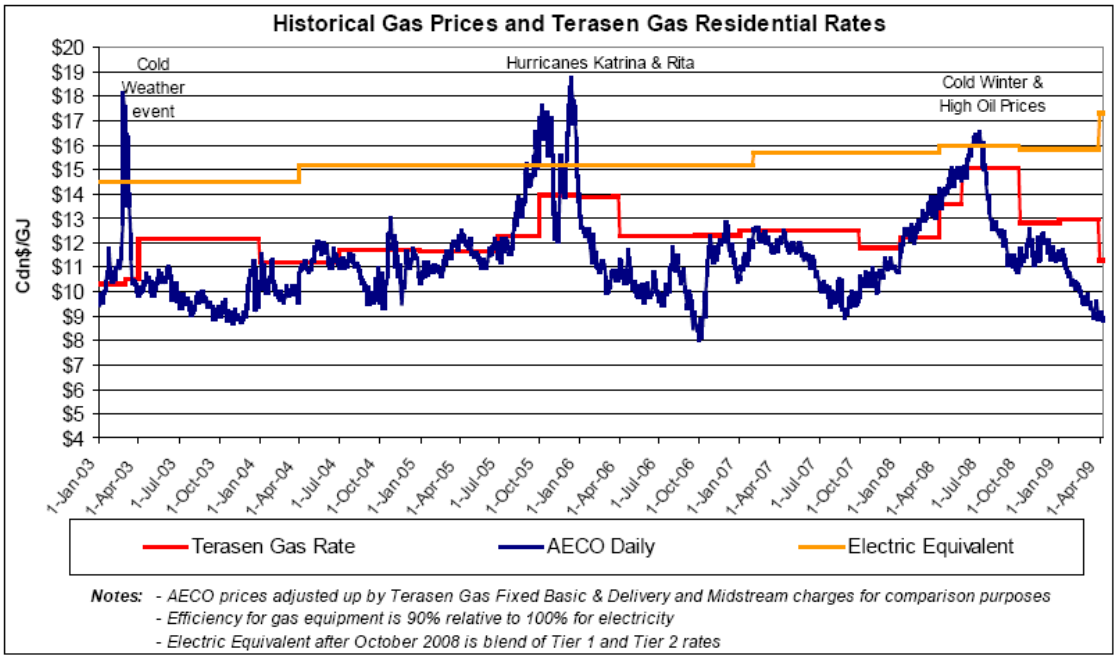


Figure C-5-4: Terasen Gas Residential Rate Compared to Market Prices



6.1. How does Terasen support a view that TGI's competitive position or cost advantage of natural gas over electricity continue to decline, when the evidence provided in Appendix C-26 shows a dramatic improvement recently as a consequence of BC Hydro's introduction of its RIB rate?

Response:

Before responding directly to the question and the information displayed in the charts, TGI will address its competitive position vis-à-vis electricity from the standpoint of policy and public perception because these are as much or more at issue than assessing the relative competitiveness using numerical analysis of natural gas and electricity rates. The challenge for natural gas from the bigger picture in this area involves the confluence of a number of factors:

- Government policy and legislation intended to reduce GHG emissions (which means generally less consumption of fossil fuels),
- Growing public sentiment ("green") against the use of fossil fuels and in support of reducing GHG emissions,
- Public perception regarding fossil fuel-based energy prices and future carbon taxes. Although natural gas commodity prices are relatively low currently, significantly higher prices and price volatility are in recent memory. Public discussion of climate change and the need to implement carbon taxes or cap and trade regimes to reduce GHG emissions is a daily discussion. This is further compounded by the public perception that BC Hydro electricity supply is an "all green solution". TGI believes that perceptions are often as much an influence in public behaviour with respect to energy use as reality is.
- Other trends such as "densification" of urban areas in B.C. (resulting in part from the desire of governments to be greener and reduce GHG emissions). Densification means more multi-family dwellings and less single family detached housing where TGI has had its highest market share.

The changing housing mix, changing government priorities and changing public perceptions mean that natural gas may no longer be the fuel of choice for an ever growing segment of the population within the service area.

With the foregoing being said, one of the challenges that TGI has faced in recent years and which it believes it will continue to face is strong price competition in BC from electricity on an operating cost basis. Between 1998 and 2008, the price advantage of natural gas compared to electricity in BC declined from 63% to 18%. The price advantage of natural gas to electricity has gradually declined as natural gas rates increased with rising commodity costs, while electricity rates remained relatively constant.

TGI would like to point out that the charts contained in Appendix C-26 that are referenced in the preamble to this question, are calculated using an efficiency factor of 90% and the total natural

gas use within the home. Given that the average efficiency level may vary from home to home depending on the efficiency and mix of the applications that the natural gas is being used in, TGI has restated Appendix C-26 using a 75% average efficiency as well as 90% to provide a range of outcomes (please refer to the response to BCUC IR 1.1.3). In general, the lower the efficiency of the home, the less the operating cost advantage is for natural gas as compared to either Step 1 or Step 2 electricity rates.

Terasen Utilities agree that, as a result of the introduction of BC Hydro's RIB rate, on an operating cost basis (i.e., excluding the upfront capital and maintenance cost differences between a natural gas and an electric heated home) that natural gas does currently have an operating cost advantage against a home heated by electricity, particularly for single family dwellings and higher volume residential electricity consumers. However natural gas needs a significant operating advantage over electricity in order to recoup the extra upfront capital costs and ongoing maintenance costs of a gas-heated dwelling relative to an electrically-heated dwelling. The magnitude of the operating cost advantage needed is estimated to be in the $10/GJ range for a new single family home in the Lower Mainland (See Figure A-7 on page 64 of the Application). Also, in the new construction market, developers, that do not benefit themselves from the lower operating costs of a natural gas heating system, will often decide against installing gas because they are uncertain of whether they will be able to recover their additional upfront capital costs in the selling price of a home. So even if it appears that there is a large operating cost differential a gas heating system may not be installed.

Unless BC Hydro's overall rates rise substantially and the RIB Step 2 rate better reflects the cost of new electricity supply, TGI believes the competitive position of natural gas versus electricity will remain challenged. Some customers of BC Hydro will only be charged the Step 1 rate for space heating provided by electricity. Thus, it is important to consider both Step 1 and Step 2 rates and its impact on the competitive position of natural gas against electricity. In addition, the BCUC Decision on BC Hydro RIB Application is not prescriptive as to how the changes will be made on the RIB Step 2 once a new pricing point has been established for the cost of new supply (BCUC Order No G-124-08, page 108).

Further, future increases in the cost of natural gas and the carbon tax could erode the current operating cost advantage that natural gas currently enjoys. Figure A-5 and Figure A-6 on pages 62-63 of the Application reflect the potential upward movement on natural gas prices from current forecasted levels.

6.2. Isn't TGI better off with BC Hydro's RIB rate in place than without it?

Response:

The implementation of the RIB rate structure which has price signals linked to the marginal cost of electricity may have beneficial impacts on the use of natural gas relative to electricity. Beyond the potential negative influences of public perception and government policy (as discussed in TGI's response to CEC IR 1.6.1) there are other qualifying factors which suggest that the improvement to the competitive position of natural gas may not be as significant as a simple comparison against the RIB Step 2 rate would imply.

First, for many customers the space and water heating energy requirements for a dwelling do not all come from consumption above the RIB Step 2 volume threshold. The Step 1 rate is very low since it is calculated residually and is largely reflective of the fact that a large majority of BC Hydro's cost structure is based on low cost power from Heritage resources. TGI will continue to face competitive challenges based on the fact that the RIB Step 1 is as much or more the relevant comparator in many situations than the RIB step 2 rate is.

Secondly, the BCUC Decision on BC Hydro RIB Application is not prescriptive as to how the changes will be made on the RIB Step 2 once a new pricing point has been established for the cost of new supply (BCUC Order No G-124-08, p 108).

See TGI's response to CEC IR 1.6.4 for more discussion on other factors that will impact the competitive position of natural gas versus electricity.

6.3. Why does Terasen suggest that TGI's competitive position is gradually eroding, when the evidence in Appendix C-26 shows that the large competitive advantage was essentially erased in 2000 and 2001?

Response:

As discussed in the response to CEC IR 1.6.1 TGI sees the competitive position of natural gas relative to electricity as consisting of much more than a simple rate comparison. Terasen Utilities acknowledge that the operating cost advantage of natural gas versus electricity over the years presented in Appendix C- 26 has fluctuated in line with volatility in the commodity cost of natural gas. This is due to how the actual gas costs get reflected into customer rates.

As discussed in the response to BCUC IR 1.69.3 commodity rates and the commodity cost deferral account (the CCRA) are reviewed on a quarterly basis, and typically reset when the ratio of forecast commodity recovery-to-forecast costs, on a 12-month prospective basis, falls outside the 0.95 to 1.05 threshold. Generally, when commodity rates are reset, the new rate is

designed to recover, or refund, over the next 12 months any existing CCRA account balance, along with any under or over recovery of commodity costs forecast to occur over the next 12-month period. However, due to rapid and unanticipated increases in natural gas commodity prices in late 2000 and throughout 2001 which led to unprecedented deficit levels accumulating in the Gas Cost Reconciliation Account ("GCRA"), which reduce the impact of these price increase on customers rates in the 2000 and 2001 timeframe. The large GCRA deficit at the end of 2000 was not immediately and fully passed on to the customers since BCUC Order No G-124-00 required the Company to amortize that amount over three years. In early 2001 the GCRA/ Gas Cost Flow-through Guidelines (BCUC Letter No L 5-01) reaffirmed the three year amortization of the 2000 balance but established a one year amortization for the new balances accruing after December 31, 2000. These facts introduced distortions into the graph presented in Appendix C-26 that strengthen the perception that the erosion of the operating cost advantage of natural gas versus electricity all occurred in 2000 and 2001.

If this large deficit had not been recorded in GCRA or if it was recovered over a one-year amortization period the graph shape in Appendix C-26 would be one of higher natural gas cost in 2000 and 2001, followed by lower costs in 2002-2004. To be fair, there were large increases in natural gas commodity prices in 2000 and 2001, but these were largely event-driven (i.e. the California energy crisis). If one focuses on the longer term trend in natural gas commodity prices rather than on the distortions caused by short term spikes and market volatility TGI believes it is appropriate to characterize the compression between natural gas and electricity costs as gradual.

It also should be pointed out that the operating cost advantage that natural gas displays in Appendix C-26 is needed to contribute to the difference in upfront capital and ongoing maintenance costs for a home heated by natural gas as compared to one with electricity. Also, in the new construction market, developers, that do not benefit themselves from the lower operating costs of a natural gas heating system, will often decide against installing gas because they are uncertain of whether they will be able to recover their additional upfront capital costs in the selling price of a home. So even if it appears that there is a large operating cost differential a gas heating system may not be installed.

6.4. In fact the BC Hydro RIB rate appears to be headed toward restoring the natural gas competitive advantage does it not?

Response:

The establishment of the RIB rate structure for the residential customers and the future establishment of similar rate structures in other classes may help the competitive advantage position of natural gas versus electricity at some time in the future. However there are many

uncertainties that will affect the competitive position of natural gas versus electricity in the future and these uncertainties are discussed below:

- The RIB Step 2 rate is not the only relevant comparator to the residential natural gas rates in all cases. Smaller and more energy efficient dwellings may get much or all their space and water heating energy requirements from electricity consumption below the Step 2 consumption threshold.
- Natural gas operating costs for space heating need to be significantly below the comparable electricity costs in order to recover the extra upfront capital costs for natural gas space heating equipment relative to electricity. The costs of electricity needs too exceed the cost of natural gas by an amount in the order of $10/GJ ((See Figure A-7 on page 64). TGI would like to point out that the charts contained in Appendix C-26 that are referenced in the preamble to this question, are calculated using an efficiency factor of 90% and the total natural gas use within the home. Given that the average efficiency level may vary from home to home depending on the efficiency and mix of the applications that the natural gas is being used in, TGI has restated Appendix C-26 using a75% average efficiency as well as 90% to provide a range of outcomes (Please see BCUC IR#1.1.3). In general, the lower the efficiency of the home, the less the operating cost advantage is for natural gas as compared to either Step 1 or Step 2 electricity rates.
- Carbon taxes and other disincentives against natural gas and fossil fuels consumption are likely to increase over time (beyond the $1.50 per GJ for 2012 and after). In addition public perceptions about using natural gas may continue to become increasingly negative.
- Residential gas rates are more subject to commodity market volatility within the annual cycle while electric rates are likely to change once per year as revenue requirements and rates change.
- Natural gas commodity price forecasts will change over time. Economic conditions, natural gas supply/ demand balance and other factors will change over time and expectations about the differentials between natural gas and electricity rates will change accordingly.
- The provincial government has made policy commitments in support of low electricity rates. There are several references in the 2007 BC Energy Plan in support of maintaining low electricity rates, such as, for example on page 15 where continued support of electricity trading is discussed as a means "to keep electricity rates low for all British Columbians." UCA Section 43(1.1) from 2008 amendments to the Utilities Commission Act now requires BC Hydro to file a report with the Commission annually comparing BC Hydro to electricity rates in other jurisdictions including an assessment of whether BC Hydro rates are competitive with those in the other jurisdictions. There is obvious conflict between the sustained high electricity rate increases forecast in the LTAP and the province's commitment to low electricity rates. Over the longer term the

province's commitment to low electricity rates is likely to be a factor which will moderate the rate increase that BC Hydro will ultimately be allowed to implement.

- The 2008 amendments to the Utilities Commission Act also overturned the elements of the Commission's Decision on BC Hydro's 2007 Rate Design Application pertaining to rate rebalancing between the rate classes, which, if not overturned would have increased residential rates overall by more than 10%. Whatever the reasons the provincial government may have had for overturning portions of 2007 RDA Decision, the impact of the legislation change was to reduce rate impacts for residential electricity consumers. Such interventions introduce further uncertainty into how the energy landscape and the matter of gas vs. electricity competitiveness will unfold in the future.

6.5. In fact doesn't the evidence provided in Figure A-9 above demonstrate that the marginal cost of electricity supply is far above the cost of natural gas commodity by about the same degree as was the case in 1998?

Response:

The marginal electricity supply cost line in Figure A-9 was based on the evidence from BC Hydro's LTAP proceeding that an updated value for the marginal electricity supply cost was expected to be in the range of $120/MWh. At the time that TGI's 2010-2011 RRA was prepared it was expected that the $120/MWh estimate would be validated by the results of awarded contracts coming out of BC Hydro's Clean Power Call. Recently however, the Commission's Decision on the LTAP did not approve BC Hydro's requests with respect to the Clean Power Call. TGI believes that this Commission decision with respect to the Clean Power Call has placed considerable uncertainty on the cost of new electricity supply, in terms of both the amount (i.e., does $120/MWh continue to be valid) and the timing of when a new benchmark for the marginal cost of new electricity supply will be established.

The difference between natural gas commodity costs and the marginal cost of electricity supply will only affect the relative competitiveness of natural gas against electricity if it is somehow reflected in customer rates so that behaviour is influenced by price signals. Other factors beyond costs can influence consumers purchasing decisions, these can include customers perception towards a product or service and government policies that send signals to customers on what things to consider when making an energy choice for the long term. Please refer to the responses to CEC IR 1.6.2 and CEC IR 1.6.4 for further discussion on why the RIB rate structure is only partly effective in conveying marginal price signals to residential electricity customers.

6.6. Does Terasen understand BC Hydro's approach to electricity rates as being one of trying to provide the appropriate marginal cost price signal?

Response:

TGI is aware of BC Hydro's plans to implement marginal cost price signals and conservation rate structures in its various customer classes. TGI supports BC Hydro's efforts in this direction. According to the Commission Decision on the BC Hydro RIB application in 2008, BC Hydro is to bring proposals forward to the Commission on how to work this new call price into rates.[1] Therefore, the price signal to the consumer about the marginal price of power, more than likely will be masked given that this new call for power ($120/MWh) is about 44 per cent higher than the current Step-2 rate (as of April 1, 2009 the Step-2 rates is $82.7/MWh).

Please see the response to CEC IR 1.6.2 for discussion of issues that may limit the benefit for natural gas competitiveness that can be achieved from marginal cost price signals in electricity rates.

6.7. Does Terasen agree that (a) both BC Hydro and the BC Utility Commission under the UCA are required to undertake all cost effective DSM measures before pursuing new supply (b) rate designs are cost effective DSM measures (c) that BC Hydro by its own evidence has stated that the RIB rate design and its other conservation rates are a starting point and that they expect to continue to develop conservation through rates in the future (d) that the RIB rate design at the present time falls short of providing the marginal cost of new supply price signal (e) that the RIB rate design can be cost effectively modified in the future to achieve additional conservation and provide a price signal which more closely signals the marginal cost of new supply?

Response:

TGI agrees generally with CEC's observations, with the provisions noted below, and provides the following comments on each of the items:

[1] BC Hydro 2008 RIB, Commission Decision page 108 states: "In addition the Commission Panel includes in its conditional design principles an instruction that, when circumstance dictate, BC Hydro must file an application to change its estimate of the cost of new supply and to include in that application a proposal on how to phase in the change, so that the allocation of reviews requirement increases between the Step-1 and the Step-2 rates will be reviewed on a case by case basis each time BC Hydro makes an application change its estimate of the cost of new supply".

(a) The UCA does not itself specifically require BC Hydro to adopt all cost effective DSM before acquiring new supply, but implicitly suggests a preference for cost-effective DSM. UCA Section 44.1 (2) (b) requires a utility, in the context of a long term resource plan filing to submit "a plan of how the public utility intends to reduce the demand referred to in paragraph (a) [the pre-DSM forecast demand] by taking cost-effective demand-side measures". UCA Section 44.1 (2) (f) further requires a utility to provide an explanation of why the demand it plans to serve by the acquisition of new supplies or the construction of new facilities are not planned to be replaced by demand-side measures.

(b) With the qualification that not all rate designs are intended to produce conservation, TGI agrees using rate design as a demand side measure to produce conservation is generally a cost effective approach.

(c) Terasen Utilities understand that BC Hydro is planning to introduce conservation rates in its customer classes and that the RIB rate structure is the first step in implementing conservation rates to the residential class. For example BC Hydro made the following statement in an IR response in the RIB Application proceeding:

> *"BC Hydro's proposed RIB rate is a first step in restructuring residential rates. BC Hydro sees the implementation of a RIB rate structure as an immediate and appropriate first step that does not preclude implementation of any other future rate structure. Indeed, the RIB rate may facilitate customer acceptance of future, more complex rate designs. BC Hydro does not believe that moving forward with the proposed RIB rate will impact or bias either BC Hydro's or the BCUC's future evaluation of other rate structures, including TOU or CPP"* (RIB Exhibit B-3, BCUC IR 1.5.1).

(d) TGI agrees that the current RIB rates fall short of sending the full marginal price signal based on the marginal cost of new supply. In the 2008 LTAP hearing BC Hydro indicated that an updated estimate of the cost of new supply is in the range of $120/ MW or 12 cents/kWh (2008 LTAP Hearing, Transcripts, Volume 3, Page 264). At the present time the RIB Step 2 rate is 8.27 cents / kWh suggesting that the price signal is less than the marginal cost of new supply. The recent LTAP Decision denying BC Hydro's Clean Power Call requests may affect the establishment of an updated cost of new power (in both timing and amount) for the purposes of establishing a new RIB Tier 2 rate, however it is fair to expect that an updated cost of new electricity supply will be higher than 8.27 cents / kWh.

Having an inclining block structure in which the price signals based on the marginal cost of new supply is only part of the picture as far as the issue of gas - electricity price competitiveness is concerned. As far as gas pricing is concerned the RIB Step 2 rate is the applicable comparator in some cases but not all. The RIB Step 1 rate is very low since it is calculated residually and is largely reflective of the fact that a large majority of BC Hydro's cost structure is based on low cost power from Heritage resources. The

Terasen Utilities will continue to face competitive challenges based on the fact that the RIB Step 1 rate is as much or more the relevant comparator in many situations than the RIB Step 2 rate is. There are also other issues involved in gas-electricity competitiveness that are not directly related to price, which have been described in other responses.

(e) TGI agrees that the RIB rate design can be cost effectively modified in the future to achieve additional conservation and provide a price signal which more closely signals the marginal cost of new supply. However modifications to the RIB rate structure or the implementation of different conservation rate structures designed to reduce electricity consumption do not necessarily lead to into an improved competitive position for natural gas. For example, time-of-use rates may be designed to shift electricity use from peak to non-peak periods to achieve system capacity benefits. Time-of-use electrify rates may be a cost effective demand-side measure for electricity but their cross-impact on natural gas use is likely to be minimal. Again, there are also other issues involved in gas-electricity competitiveness that are not directly related to price, which have been described in other responses.

TGI believes that introducing marginal cost price signals into electricity rates in BC is an appropriate direction to pursue. The establishment of the RIB rate structure for residential customers and the future establishment of similar rate structures in other classes or other conservation rate structures may help the competitive position of natural gas versus electricity; however there are many possible variations in the approach to achieving conservation through rate structures and the ultimate benefit or detriment to natural gas will also vary with the approach taken.

6.8. Is there not a strong possibility that TGI's competitive position could in fact continue to improve into the future as a result of the fact that the Provincial Government has addressed the very problems, with respect to the embedded cost pricing of electricity and the market pricing of natural gas, which Terasen has been pointing to as one of the primary sources of a potential competitive price disadvantage?

Response:

Please see TGI's response to CEC IR 1.6.1, 1.6.2 and 1.6.4.

6.9. Does Terasen agree that its ability, provided through regulation, to smooth out the volatility of natural gas price swings in the market, as demonstrated in Figure C-5-4 above, assist TGI in defending its competitive position versus natural gas?

Response:

TGI has assumed that the question meant to say "TGI in defending its competitive position versus electricity".

Terasen Utilities maintain an active commodity price risk management program to manage commodity prices and dampen volatility through our hedging activities which however do not mitigate the Company's potential business risk arising from the uncompetitiveness of the price of natural gas versus electricity. Hedging is a proactive approach by the company to help us remain competitive on behalf of our customers.

The price of natural gas fluctuates according to forces of demand and supply fundamentals of natural gas while the price of electricity is based predominantly on Heritage costs. In an attempt to manage the price volatility Terasen Gas applies hedging mechanisms. TGI's quarterly review process which adjusts rates based on a 12-month forecast also mitigates the effects of short-term volatility in commodity prices to some degree.

Despite the hedging activities and the quarterly rate setting process Terasen Gas does have business risk arising from price volatility. Customers still experience increases and decreases in their rates as frequently as quarterly due to changing natural gas market conditions. TGI believes that customer perceptions of gas price volatility, based on reporting in the media, have as much or more of an influence on customer behaviour as the actual changes in commodity rates do. Customers are concerned with the volatile nature of natural gas prices and are wary, even when prices are low, that they might again find themselves in a situation where natural gas is no longer the economic choice. Customers associate price volatility with the overall costs and the spikes have caused many customers to install more efficient systems or augment their use of natural gas with other energy sources including electricity. This results in lost throughput which puts upward pressure on natural gas delivery rates, exacerbating the competitive price challenge.

Changes in both the commodity cost of natural gas and the volatility[2] of the commodity price have changed customers' and the public's perception of natural gas as a fuel of choice for space and water heating.

[2] Residential Customer Price Volatility Preference Survey, Final Report Dated April 15, 2005 states on page 2: "A sizeable proportion (71%) of respondents expressed concern about future fluctuations in the price of natural gas. Respondents tended to be more concerned about future prices fluctuations in the price of gasoline and natural gas, than they were about price fluctuations in the cost of telephone or electricity".

7. Reference: Exhibit B-1, Page 4, Executive Summary – Economic Conditions

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 reduce customer demand for energy consumption. In addition to this economic downturn, Terasen Gas faces demographic

7.1. Does Terasen expect economic conditions to change from time to time, such that cycles in the economy would be regular recurring events which it could anticipate occurring and could therefore plan strategies for confronting the challenges which come with such economic cycles?

Response:

Although economic conditions tend to change from time to time, most of the fluctuations in economic activity do not follow a predictable periodic pattern, nor are the economic conditions similar between cycles. The Company plans on an annual basis for gas forecast usage and customer additions, and on a longer term basis for infrastructure requirements. The timing, nature and impact of economic cycles are not predictable in a way that can provide the Company with meaningful ways to alter the prudent way in which TGI manages its business.

7.2. Does Terasen plan for economic cycles, the consequent conditions and the implications?

Response:

Economic conditions or cycles are considered as external influences that impact the underlying assumptions which contribute to determining the demand forecast for natural gas as well as customer additions and resource planning. TGI does consider economic conditions in the forecast of demand for natural gas, including the forecast number of customer additions and the need for infrastructure. As mentioned in TGI's response to CEC IR 1.7.1, given that most of the fluctuations in economic activity do not follow a predictable periodic pattern nor is the impact consistent amongst cycles, the Company cannot plan for these economic expansions and contractions with certainty, but does consider economic conditions in a reasoned manner to ensure prudent planning.

7.3. Does Terasen believe that the economic cycles affect the commodity cost or price of natural gas?

Response:

The commodity cost of natural gas is determined by many factors, including increased demand or decline in demand caused by economic cycles.

8. Reference: Exhibit B-1, Page 4, Executive Summary – Accounting Changes

Canadian accounting standards are entering a time of unprecedented change. Canadian utilities will be required to comply with International Financial Reporting Standards ("IFRS") for financial reporting periods commencing on or after January 1, 2011. Comparative figures for 2010 must also be restated to be in compliance with IFRS. These changes in accounting policies will affect the timing of when costs are recovered and thereby affect the determination of the Company's revenue requirements and rates. Related to this issue, it is expected that rates will rise in the short term, but that this will be offset by lower rates in the future. Accounting changes are the most significant driver of the rate increases

8.1. Have the IFRS Accounting Standards been finally determined with respect to regulated utility accounting?

Response:

The final IFRS has not been issued and it will not likely be finalized until mid-2010. An exposure draft on Rate-regulated Activities was released on July 24th, 2009 with comments expected to be received on the exposure draft by November 20th, 2009. The current exposure draft, subject to the comments received from interested parties, may change and is not a final standard.

8.2. Has Terasen examined options as to how it may choose to handle its accounting requirements under IFRS?

Response:

Terasen Gas has examined the major accounting policy options and requirements under IFRS as well as the related impacts to Terasen Gas. These policy options and requirements, and TGI's approach to them, are discussed in the RRA under Tab 11. Accounting and Other Policies (pgs. 474-484). The significant areas in accounting policy options and requirements under IFRS discussed in this section are:

- Regulatory Assets and Regulatory Liabilities (Deferral Accounts) under IFRS
- Property, Plant & Equipment (including valuation, capitalization policies and others)
- Provisions, Legal and Constructive obligations
- Depreciation

- Income Taxes
- Pension and Employee Future Benefit Costs
- Leases

8.3. Has Terasen explored whether or not there may be a "constructive obligation" which may require accounting treatment, whenever TGI's regulator makes a revenue requirement and rate determination ruling, particularly where the regulator may opt for the use of deferral accounts?

Response:

If the question is intended to ask whether decisions of the regulator create a constructive obligation by themselves, so that the resulting constructive obligation must be recognized under IFRS, then TGI has not explored this concept, and has not heard it mentioned in discussions with other utility working groups.

8.4. Has Terasen examined and modeled its future TGI rates related to the proposed increase in rates in the short term and the offsetting lower rates in the long term and if so can these be provided?

Response:

Terasen has not examined and modeled its future TGI rates related to the proposed increase in rates in the short term and the offsetting lower rates in the long term. Since the lower rates are long-term in nature, such an undertaking would require detailed forecasts for many years into the future, as some of the asset lives involved are in the range of 50 years. For any specific cost item, capitalization does not change the total amount of the cost to be recognized, so any time that more costs are recognized today there will be less available to be recognized in the future.

9. Reference: Exhibit B-1, Page 5, Executive Summary – Operational Excellence

Terasen Gas is committed to continuous improvement and Operational Excellence for the benefit of its customers and shareholders. For Terasen Gas, Operational Excellence means the prudent combination of service quality to our customers, and the cost of providing those services, while ensuring employee and public safety, and operating in an environmentally responsible manner. TGI's strong corporate

9.1. How does Terasen balance the tradeoffs between Customer Service Quality and the Cost of Providing Service?

Response:

Recognizing the need to balance not only the tradeoffs between service quality to our customers and the cost of providing service but also ensuring employee and public safety, operating in an environmentally responsible manner and prudent financial management, Terasen Gas uses the balanced scorecard approach. The balanced scorecard: provides Terasen Gas with the focus to deliver on a series of key success measures critical to its business; aligns its business activities; and, maintains its focus on Operational Excellence for the benefit of customers and the shareholder.

To ensure the appropriate focus and balance, specifically on the 2009 scorecard, customer service quality as reflected in the Customer Satisfaction measure is weighted in importance relatively similar to O&M per customer, a measure for the cost of providing service. Targets are set for these two measures recognizing the need to find an appropriate balance that ensures value for ratepayers. To monitor and ensure the quality of customer service, benchmarks such as the existing service quality indicators are utilized.

9.2. Isn't prudence a basic minimum test for utility operation as opposed to excellence, which would be presumed to be some elite level among prudent peers?

Response:

Prudence is a minimum requirement for utility operation and is inherent in Terasen Gas decision making process. In the context of the quoted passage we were using the term "prudent" more informally, as being synonymous with "considered", "appropriate" or "optimal". Terasen Gas strives for more than a minimum level of operational performance. Terasen Gas' current vision

is to be a leading provider of energy transportation and utility infrastructure management services. In order to achieve its vision, achieving Operational Excellence is paramount.

As outlined in its statement above, Terasen Gas defines Operational Excellence to mean the prudent (or optimal) combination of the different success measures that are important to its business. It is not that we will excel in all categories of the measures relative to "prudent peers," but that instead we strive to reach the optimal balance and alignment of the business activities for the benefit of customers and the shareholder.

9.3. If Terasen wishes to use excellence and prudence to mean the same thing, what terminology would Terasen prefer for referencing top 5% performance among relevant peers?

Response:

Please see the response to CEC IR 1.9.2.

10. Reference: Exhibit B-1, Page 5, Executive Summary - Customer Service Value

Customers have realized significant value over the PBR Period in the Company's delivery of safe, reliable and cost effective service. Over the PBR Period, Terasen Gas has achieved record high levels of customer satisfaction and has generally met or exceeded the levels set out in the Service Quality Indicators ("SQIs"). At the same time, customers also saw delivery rates hold steady when compared to

	Performance Indicator	Benchmark	2003 Annual Actual	2004 Annual Actual	2005 Annual Actual	2006 Annual Actual	2007 Annual Actual	2008 Annual Actual	2003 - 2008 Average	2009 YTD April Actual
8	Independent Customer Satisfaction Survey	Compared to prior years	73.9%	73.9%	77.2%	77.9%	79.3%	79.7%	77.0%	79.9%

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Transportation Bills Accurate. During 2008 and Q1 2009, Terasen Gas has experienced declining performance in key SQI measures that are delivered by Accenture Utilities BPO Services ("AUBPOS") under the contract with CWLP. We have also been challenged with the impacts of staff turnover in the

10.1. At Part III Section B – Tab 1, Page 115 Terasen's customer satisfaction level is at 79.9% in 2009 up from 73.9% in 2003. Does this represent a prudent level of satisfaction or is this an operational excellence?

Response:

For Terasen Gas, Operational Excellence means the prudent combination of service quality to our customers, and the cost of providing those services, while ensuring employee and public safety, and operating in an environmentally responsible manner. Operational Excellence is a philosophy of leadership, teamwork and problem solving resulting in continuous improvement throughout the organization by focusing on the needs of the customer, empowering employees, and optimizing existing activities in the process.

Customer satisfaction is a relative measure and elements beyond the Company's control can influence overall customer satisfaction results. Terasen Gas measures customer satisfaction consistently and results indicate an increase in overall customer satisfaction since 2003.

Terasen Gas believes current customer satisfaction ratings are strong, however it must continue to monitor customer satisfaction in order to understand customer perceptions of the Company's performance. This will also enable Terasen Gas to identify any changes in customer needs and expectations related to the Company's performance in order to respond to those changes. Customer satisfaction results are compared to historical performance and can be influenced by

factors that are beyond the Company's control. Terasen Gas believes that as customer expectations change over time, it will need to change to meet those expectations and maintain the currently strong customer satisfaction results.

10.2. If this level of customer satisfaction is operational excellence, is Terasen content with this level of performance or does Terasen believe that it should be trying to raise customer satisfaction from the current level?

Response:

Please see the response to CEC 1.10.1.

10.3. If Terasen believes it should be trying to raise customer satisfaction above the current level, to what level does Terasen believe it should be trying to reach?

Response:

Terasen Gas believes current customer satisfaction ratings are strong and should be maintained. TGI must continue to monitor customer satisfaction in order to understand customer perceptions of the Company's performance. Customer satisfaction results are a relative measure and are compared to historical performance. Terasen Gas believes that as customer expectations change over time, it will need to change to meet those expectations.

10.4. If Terasen believes that the current level of customer satisfaction is operational excellence then what does Terasen believe it should be doing about the 21.1% of customers surveyed who do not believe that the current level of service is satisfactory let alone operationally excellent?

Response:

We believe that our customer satisfaction results are strong and should be maintained, however the pursuit of operational excellence does not translate to a 100% satisfaction rating. TGI does not believe it would be a prudent use of customer's money to strive for 100% satisfaction as it is unlikely that 100% could be achieved as there will always be those customers who are not

satisfied. Further, as TGI strove to reach higher levels of satisfaction, the cost to do so would exponentially increase. Terasen Gas evaluates both positive and negative results in its customer satisfaction studies to ensure an understanding of areas where performance is rated positively by customers and where customers are not reporting satisfied ratings, identifying potential areas for improvement.

The Customer Satisfaction Index is a composite score derived from four studies: the Residential Customer Satisfaction Study; Small Commercial Satisfaction Study; Large Commercial Satisfaction Study, and the Builder and Developer Satisfaction Study. The results from each of these studies are weighted to reflect the relative size and service demands of each the groups surveyed. The residential customer study contributes 75% of the overall score, the builder/developer and large commercial studies each contribute 10% and the small commercial study contributes the remaining 5%.

Within the Residential Study Billing and Call Centre attributes contribute 1/3rd of the score; another 1/3rd is attributed to Corporate Image and Marketing, while the final third is split between The Product (13%), Emergency Calls (12.7%,) and Meter Exchanges/New Services (5.6%).

The overall weight of the residential study makes it difficult to improve the overall customer satisfaction index score by improving services to commercial customers and the builder/developer community. The division of weightings within the residential study also preclude a magic bullet approach to improving scores; instead the incremental improvements seen over the previous five years are testament to Terasen Gas' cost-effective approach of maintaining performance in well rated areas and focusing on improvement opportunities.

We believe that our customer satisfaction scores are strong, but also allow for improvement as customer needs and expectations change.

10.5. At Part III Section B – Tab 1 - page 116 Terasen states that its SQI measures are declining for 2008 and into 2009. Does this decline represent operational excellence in Terasen's performance? Does this decline represent continuous improvement in Terasen's performance?

Response:

Terasen Gas was not satisfied with the Customer Care related SQI results in 2008 that did not meet performance targets (SQI 3, 5a and 5b), nor with the Customer Care related SQIs that were not meeting targets (SQI 5a and 5b) as reported for 2009 YTD April in Table B-1-4 of the 2010-2011 Revenue Requirement Application. Please see the responses to BCOAPO IR 1.15.5 and BCOAPO IR 1.15.6 for additional information regarding this topic.

10.6. What are the implications for Terasen and TGI whenever it does not meet its SQI benchmarks or whenever it does not continuously improve its performance for the benefit of customers?

Response:

If Terasen Gas does not meet SQI performance benchmarks or does not provide continuous improvement for customers, customer dissatisfaction can result in the immediate term. In the long term, this can negatively impact subsequent customer growth opportunities. As a result, TGI takes underperformance in meeting SQI benchmarks seriously and responds appropriately to change the outcome of the SQI.

Further, under the PBR Agreement significant deviations from the SQI's could lead to limitations on TGI's incentive payment. TGI notes that no such limitations on TGI's incentive payment occurred through the PBR period.

10.7. Given that Terasen is now embarked on a major undertaking to replace its customer systems and to insource many of its customer service functions does Terasen agree that it may be increasing its risks for meeting customer SQI's?

Response:

No, TGI does not believe that it is increasing risk for meeting customer service levels in undertaking the Customer Care Enhancement Project.

At the present time, under the current outsourcing agreement which will remain in place in its present form throughout the RRA period, there are financial incentives for the service provider to meet SQIs. Critical customer service level metrics include financial penalties for non-performance. These penalties are effective in the month the deficiency is identified and are applied again in the month following if not corrected. The penalties increase exponentially if the deficiency continues beyond the first two months with the penalty amount doubling each month.

After the project is in place, anticipated for 2012 (after the RRA period), we believe for the reasons set out in the CCEP Application that we will be able to better respond to evolving customer needs and thus provide a higher quality of service to our customers in the long term.

10.8. Given that Terasen's stated goals are to achieve a prudent balance between quality customer service and the cost of providing the service, while ensuring safe, reliable service in an environmentally responsible manner, does Terasen have benchmarks for (a) cost of service (b) safety (c) reliability of service and (d) environmental responsibility?

Response:

For the items noted, Terasen Gas uses the following measures and benchmarks to guide its actions towards achieving its goals.

- Cost of service – O&M per customer target as reported on the scorecard.
- Safety
    - employee safety target reported on the scorecard as Recordable Vehicle Accidents and Recordable Injuries.
    - public safety target tracked in the service quality indicators as Emergency Response Time.
- Reliability of Service – a number of measures and targets are used including:
    - number of Transmission reportable incidents target as a measure of Transmission system integrity.
    - number of third party distribution system incidents as it may affect our service to customers.
    - leaks per kilometre of main as a measure of asset reliability.
- Environmental Responsibility
    - for environmental incidents, our goal is to have zero externally reportable environmental incidents.
    - for carbon emissions (CO_2e: carbon dioxide equivalent), our goal for Terasen Gas Mainland is to meet our year 2000 emissions baseline, net of carbon offset purchases (which is equivalent to Kyoto requirements, which is 6% below year 1990 level).

10.9. Given that it is a considerable concern to customers whether or not the Terasen service is competitive with alternative sources of service why doesn't Terasen include the competitiveness of its delivered product as a key service quality issue for customers?

Response:

Satisfaction with Terasen Gas and the competitiveness of its product is addressed in TGI's customer satisfaction service quality measure. The customer satisfaction measure is a composite index that combines customer satisfaction results of four primary market segments – residential, builders and developers, large commercial and small commercial customers. Each study includes questions related to satisfaction and the overall value of Terasen Gas' service.

In particular, the residential study includes a question related to the overall price competitiveness of Terasen Gas. The builders and developers study also includes specific questions related to the cost of installing natural gas service, the operating cost of natural gas for end customers, the overall value of TGI's service and the likelihood of builders and developers to recommend natural gas as a fuel source for heating applications.

10.10. Given that a growing and significant segment of the market, multifamily dwellings, have a significant non capture rate, reflecting a lack of satisfaction with Terasen's delivered products, has Terasen considered whether or not this would be a key service quality measure?

Response:

TGI disagrees with the premise of the question that the non-capture rate in multifamily dwelling sector reflects a lack of satisfaction with TGI's delivered products. The housing market has changed in British Columbia in recent years, with a higher proportion of new multi-family dwelling construction within the overall market. As discussed in TGI's response to BCUC IR 1.42.3 and BCUC IR 1.46.1, we are unable to estimate capture rates for multifamily dwellings prior to 2007. Our estimated capture rates for 2007 and 2008 indicate that we are attaching approximately 20% of new multifamily dwellings. TGI's capture rate in this market reflects that in cases of entry level and low price point developments, unit pricing is a primary differentiator. Electric baseboards are a lower capital cost home heating alternative in these situations and remain the heating source of choice for entry level and low price point consumer markets.

TGI does not believe that using the capture rate for multifamily dwellings as an SQI would be useful. As indicated above, the capture rate in this market sector is stable and the non-capture rate is affected by factors beyond TGI's control. Satisfaction with Terasen Gas and its product generally is addressed in TGI's customer satisfaction service quality measure. The customer

satisfaction measure is a composite index that combines customer satisfaction results of four primary market segments – residential, builders and developers, large commercial and small commercial customers. Each study includes questions related to satisfaction and the overall value of Terasen Gas' service.

Although TGI does not support the use of the capture rate for the market segment as an SQI, TGI is endeavouring to increase its capture rates. In order to increase capture rates within the multi-family dwelling market, the Terasen Utilities have three regional sales teams focused primarily on maximizing natural gas use in residential new building construction. Our primary target is space and water heating, followed by lifestyle applications like fireplaces, cooking, barbeques, dryers, etc.

We have primarily been focused on the Multi-family dwelling business, understanding that this form or housing has an appeal to first time home buyers, and as demographics change, for those interested in downsizing. This building type has also recently found favour with municipal planners interested in increasing urban density as a strategy in support of greener communities.

Our focus in this market begins at the planning stage with architects, engineers and builders/developers ("AED's"). Generally through our contacts in the industry, we are aware of plans prior to the building permit stage, and have an opportunity to influence fuel choice. We have developed special products targeted specifically at this market as well (vertical subdivisions, piping-to suites, and thermal metering being recent examples). Early influence and special products can make a difference in fuel choice. However, as noted above electric baseboards remain the heating source of choice for entry level and low price point consumer markets.

Recently, we have been successful in working with AED's on hybrid solutions – combining gas requirements with renewable heat sources like geoexchange and waste heat recovery. These hybrid solutions are perfect examples of how traditional gas utility service offerings must evolve to include alternative energy sources to optimize value for our customers, while minimizing the carbon footprint of the building. Hybrid solutions will form a fundamental service offering for the Terasen Utilities in this market now and into the future.

10.11. Given that Terasen has taken up the conservation and efficiency challenge and is encouraged to do so under the 'government's objectives' and the BCUC is required to consider this in considering approvals for Terasen expenditures, why doesn't Terasen have efficiency of service as a key service quality issue for customers?

Response:

Terasen Gas is not proposing any SQI measures for the period of the RRA. However, the current SQI customer satisfaction measures already incorporate energy efficiency and conservation. The customer satisfaction measure is a composite index that combines customer satisfaction results of four primary market segments – residential, builders and developers, large commercial and small commercial customers. Studies include questions related to energy efficiency and conservation.

For example, the residential study includes questions about Terasen Gas informing customers about energy saving opportunities and encouraging customers to take action and save energy. The large commercial study requests customer ratings on Terasen Gas providing information on energy efficient equipment and suggesting how customers can be more efficient in their gas use.

11. Reference: Exhibit B-1, Page 5, Executive Summary - PBR and Operational Excellence

During the PBR Period there have been a number of significant changes in the external environment experienced by TGI. The Company has successfully managed these challenges, while delivering Operational Excellence. The efficiencies achieved to date, through activities such as the Utilities

11.1. How much has Terasen's TGI earned in enhanced ROE since the inception of PBR?

Response:

TGI's achieved ROE after sharing is compared to TGI's allowed ROE in the table below. On average for the five completed years of the PBR, the returns were enhanced by 0.8%.

	2004	2005	2006	2007	2008
Allowed ROE	9.15%	9.03%	8.80%	8.37%	8.62%
Achieved ROE post earnings sharing	9.25%	9.91%	9.64%	9.55%	9.63%
ROE above allowed	0.10%	0.88%	0.84%	1.18%	1.01%

11.2. What would be the impact on TGI if it were held to that same PBR parameters that were previously applied if they were to apply to the 2010 and 2011 period?

Response:

As indicated on page 17 of the Application, TGI believes that any future PBR will have to account for the circumstances in which TGI finds itself at that time, recognizing for instance the external situational context outlined in the Application. In determining the 2010 and 2011 rates under a PBR extension scenario, TGI would propose exogenous factor treatment for the accounting changes and other external factors that have been discussed in the Application. Additionally, the $22.4 million revenue requirement decrease associated with the rebasing of formula capital and O&M would no longer apply. As a result of these two factors, it is likely that rate proposals under a PBR extension scenario would be higher than what is proposed in this RRA.

As noted in the Application, TGI believes that opportunities for further significant efficiency gains have been exhausted; therefore, it is likely that any savings that may be achieved through the extension of the PBR in its 2004-2009 form would not be significant, although some ongoing

savings would be retained through the formula amounts embedded in the existing rate base. TGI would continue to share any earnings above or below the allowed ROE for 2010 and 2011 as calculated based on the existing PBR agreement, but the opportunities for further significant efficiency gains have been exhausted.

11.3. If Terasen has managed challenges successfully, while delivering operational excellence under PBR, why has the company dropped the concept of being held to PBR standards?

Response:

TGI does not agree with the premise of the question that it has "dropped the concept of being held to PBR standards". The accurate characterization is that TGI is not proposing an extension of the PBR. The PBR was a product of a negotiated settlement agreement among stakeholders and TGI, and yielded benefits for all parties. Based on discussions with stakeholders in late 2008 and early 2009, it was clear to TGI that the existing PBR agreement would not receive the necessary support to continue. Also, TGI believes that any future PBR would have to account for the evolving circumstances facing the companies, which are different that the circumstances faced when the PBR agreements were entered. Thus, TGI has brought forth a Revenue Requirement Application for 2010 and 2011 that follows the traditional regulatory model. TGI will, however, continue to purse operational excellence and strive for continuous improvement as the Company has demonstrated during the PBR period. TGI is hopeful that a future PBR agreement can be put in place to further align the interests of customers and the Company once this RRA period is complete.

11.4. Is the PBR process mutually exclusive from the RRA process or could they be combined in certain ways?

Response:

TGI does see the PBR process as being mutually exclusive from the RRA process. Fundamental to a PBR is the implicit agreement of the utility and intervenors that rates will be set pursuant to defined parameters and during the period of the PBR the utility will not file a RRA seeking to increase rates and the intervenors will not file a complaint seeking to decrease rates.

A PBR agreement is different than a Negotiated Settlement Process ("NSP"), which can be a way for intervenors and the Company to resolve the differences or issues contained in a RRA. In going through a NSP, elements of a past PBR could be included in the final agreement that resolves the RRA. However, by no means is a NSP that is a process to resolve the RRA the same as a PBR agreement.

12. Reference: Exhibit B-1, Page 5, Executive Summary – Management Structure

Operational Excellence. The efficiencies achieved to date, through activities such as the Utilities Strategy Project ("USP") provide evidence of Operational Excellence and the effectiveness of the new management structure now in place. While the needs of our customers and shareholder will continue

12.1. What is the percentage of cost that management makes out of the total labour cost of the company?

Response:

Per Tab 13, Schedule 28, for 2010 to 2011, it is expected that management will make up 46% of the total O&M labour cost of the company.

12.2. What was the percentage reduction in management cost achieved by the USP?

Response:

This initiative resulted in annual O&M savings of approximately $10 million across the three natural gas utilities collectively (TGI, TGVI and TGW). Approximately $4 million, of these savings can be attributed to TGI, primarily due to reductions in management personnel. The $4 million represents approximately 12% of TGI's 2003 O&M related to management labour.

12.3. Were there significant improvements in the labour cost structures for the company?

Response:

Yes. In order to complete the operational integration of the utilities, the companies made significant investments in process changes and organizational restructuring. The majority of these costs were incurred in 2003-2004, and resulted in net staff reductions totalling 115 employees (management and union) across TGI and TGVI.

The integration initiative was established to implement a single management team, along with common work processes and IT platforms to create a more cost effective and sustainable support organization across the Terasen Gas utilities (TGI, TGVI and TGW).

The initiative demonstrates Terasen Gas' ongoing commitment to operational excellence. The three companies continue to operate under a common management team and shared service structure whose benefits are being realized by the customer and shareholder.

12.4. If so what were they and what percentage reduction in labour cost was achieved?

Response:

This initiative resulted in annual O&M savings of approximately $10 million across the three natural gas utilities collectively (TGI, TGVI and TGW). Approximately $4 million, of these savings attributed to TGI, primarily due to reductions in management personnel, which in 2003 represented approximately 6% of TGI's total O&M labour costs.

13. Reference: Exhibit B-1, Page 5, Executive Summary - Customer Care Project Investment

the PBR Period, and the expectations of customers have evolved. However, with this success comes increased expectations and, when combined with changing customer expectations, evolving government policy, and changes in the competitive environment, Terasen Gas will have to invest more in its customer care service in order to improve the current levels of service to meet the evolving needs of customers. As part of this goal, the Company filed its Customer Care Enhancement Project Application on June 2, 2009, with the expectation that the new project components will be in service on January 1, 2012.

13.1. Are there any operating costs in the 2010 to 2011 time period which will be tangentially related to the Customer Care Enhancement Project and are not to be capitalized to the project because they are not direct project expenditures?

Response:

In the CCEP Application TGI has sought approval for the creation of a non-rate base deferral account attracting AFUDC and approval to record incremental operating and maintenance costs associated with the Project that are incurred prior to the Project implementation date of January 1, 2012, for the purposes of permitting cost recovery. TGI also seeks approval in the CCEP Application for the creation of a rate base deferral account into which the accumulated amount in the non-rate base deferral account will be transferred, effective January 1, 2012, for the purposes of recovering costs through customer rates. Based on these orders sought, operating costs incurred with respect to the Customer Care Enhancement Project (CCEP) will not contribute to the 2010 or 2011 Revenue requirement for TGI.

13.2. For instance will TGI be building up customer care management, supervisory and staff personnel ahead of the January 1, 2012 date in order to be fully trained up and ready to handle the transition pressures of such a significant project?

Response:

Please see the response to CEC IR 1.13.1.

13.3. For instance will there be requirements for review of company processes and procedures in order to plan for improvements in the way the customer care system is used or just simply to plan for the cross over and implementation?

Response:

Please see the response to CEC IR 1.13.1.

14. Reference: Exhibit B-1, Page 6, Executive Summary – Operational Performance

Terasen Gas has implemented an IT strategy that focuses on adopting industry best practices. Key aspects of this strategy are scheduled refreshes of key equipment, infrastructure and application software, and standardization of processes and infrastructure where appropriate.

14.1. Please provide a listing of all of the industry best practices and identify which ones TGI is following?

Response:

In the IT industry, a best practice is a technique, method, process, activity that is believed to be more effective at delivering a particular outcome than other techniques, methods, processes, etc. Best practices can also be defined as the most efficient (least amount of effort) and effective (best results) way of accomplishing a task, based on repeatable procedures that have proven themselves over time for large numbers of people. Depending on the specific area and the level of detail, the operating environment and business priorities, what "best practices" are adopted will differ from company to company. There is no definitive list of all of what various groups consider best practices for every aspect of the Information Technology industry. It suggests that the IT industry together can come up with something better than any one company can arrive at individually, and places authority in the community. The term may imply that the better practice is not universal, but depends on the specific situation. Despite the need to improve on processes as times change and things evolve, best-practice is considered by some as a business buzzword used to describe the process of developing and following a standard way of doing things that multiple organizations can use for management, policy, and especially software systems.

For Terasen Gas, the IT department has focused on key areas around the Information Technology Infrastructure Library (ITIL) framework for Infrastructure best practices. We have adapted to most of the below ITIL categories where applicable and cost effective.

Service Support

The Service Support ITIL discipline is focused on the *User* of the ICT services and is primarily concerned with ensuring that they have access to the appropriate services to support the business functions. ("ICT" is an acronym for "Information and Communication Technology".)

To a business, customers and users are the entry point to the process model. They get involved in service support by:

- Asking for changes

- Needing communication, updates
- Having difficulties, queries
- Real process delivery

The discipline consists of the following processes:

- Service Desk / Service Request Management
- Incident Management
- Problem Management
- Change Management
- Release Management
- Configuration Management

Service Delivery

The Service Delivery discipline is primarily concerned with proactive services the ICT must deliver to provide adequate support to business users. It focuses on the business as the *customer* of the ICT services (compare with: Service Support). The discipline consists of the following processes:

- Service Level Management
- Capacity Management
- IT Service Continuity Management
- Availability Management
- Financial Management

ICT Infrastructure Management

ICT Infrastructure Management processes recommend best practice for requirements analysis, planning, design, deployment and ongoing operations management and technical support of an ICT Infrastructure. The Infrastructure Management processes describe those processes within ITIL that directly relate to the ICT equipment and software that is involved in providing ICT services to customers.

- ICT Design and Planning
- ICT Deployment

- ICT Operations
- ICT Technical Support

These disciplines are less well understood than those of Service Management and therefore often some of their content is believed to be covered 'by implication' in Service Management disciplines.

Other best practices:

- Use of Gartner to review IT technologies (tactical and strategic) and trends. This also includes information on specific industry best practices.
- Desktop Refresh programs which includes proactively replacing aging desktop and laptop computers more than 4 years old. This is also an opportunity to upgrade the computer operating system and Microsoft Office applications. This reduces overall deployment costs and continually ensures computers are supported with up to date technologies.
- Other Refresh Programs include Server (5 years old), Printer, Network, and Security equipment. Proactively replacement of hardware and software reduces potential operational impact and O&M costs while providing new technologies for a more productive environment.
- Support staff that are knowledgeable of business processes and business impact.
- Support staff that are kept informed of changes to software capabilities through formal training and relevant conference / peer interaction.

14.2. Does TGI belong to any of the utility benchmarking services and if so which ones and if so what reports does Terasen have comparing TGI to others in the industry?

Response:

It is difficult to apply industry benchmarks because of individual operating differences between companies. Accordingly Terasen does not belong to any utility benchmarking services as it pertains to Information Technology.

15. Reference: Exhibit B-1, Page 6, Executive Summary – Capital Project Implementation

Terasen Gas also has an established record for successfully implementing major capital projects, helping to provide safe, reliable and efficient gas service to customers. Over the PBR Period, Terasen Gas has

15.1. Please provide a listing of all major projects implemented over the PBR period identifying the cost estimate for the project, the final completed project cost, the estimated in service date, the final delivered in service date, the business deliverables planned for the project and the completed project deliverable.

Response:

Below is a summary of the major projects over $1 million initiated and completed during the PBR period. Terasen Gas was successful in implementing most of the projects within the estimated budget and in-service date.

Project	Cost Estimate ($ million)	Completed Project Cost ($ million)	Estimated In-Service Date	Delivered In-Service Date	Deliverables	
Serpentine to Nicomekl, Surrey	1.3	2.1	2004	2006	System improvement	
Air Turbine Meter Testing Facility Enhancement	1.9	2.3	2004	2005	Enhancements required to facilitate more accurate calibration for meters.	
Desktop & Laptop Refresh	1.1	0.9	2006	2006	Replacement of existing desktops and laptop computers.	
AM/FM Geographical Information System	1.7	2.0	2006	2009	Improves Transmission plant asset management.	
Café	1.8	1.4	2006	2006	Required to support a number of key business units and processes in meeting customer growth targets.	
Secondary Containment	9.4	10.8	2006	2009	Compliance with Provincial and Federal legislation .	
IT Infrastructure Network Evergreening	1.2	0.4	2007	2007	Replace enterprise LAN switches, hubs, and firewalls.	Note 3
Prince George #2 Lateral Replacement	1.7	2.2	2007	2007	Required to support firm load growth	
Order Fullfilment Enhancements	1.1	0.5	2008	2007	Upgrade functionality to bridge process gaps and streamline customer generated orders.	Note 4
SI - E. 6th Ave & Quebec St., Vancouver	1.7	2.6	2008	2009	System improvement expedited to coincide with development of Olympic Village and other minicipal improvements.	
LNG Coldbox Upgrade	4.1	4.0	2008	2008	Mitigate risk of tube failure.	

CPCN

CPCN - Commercial Unbundling	7.0	6.2	2005	2005	Provide commodity choice to commercial customers.	
CPCN - Residential Unbundling	12.1	10.7	2007	2007	Provide commodity choice to residential customers.	
CPCN - Distribution Mobile Solution	6.2	6.1	2008	2008	Avoid risk that existing system will fai ldue to aging technology components.	
CPCN - Vancouver Low Pressure Replacement	23.1	17.5	2008	2008	System modification	

Notes:
1. Expenditures in $ millions.
2. Figures exclude AFUDC.
3. IT Infrastructure Network Evergreening is an annual project with $.4 million incurred in 2007. Shifting business priorities resulted in total spending of $1.1 million during the 2005 - 2007 period.
4. Some Order Fullfilment Enhancements were integrated with the Distribution Mobile Solution project to be more cost effective.
5. Amount approved for Distribution Mobile Solution includes the allowed 10% contingency.

15.2. Given Terasen's established record for successfully implementing major capital projects is TGI prepared to be held accountable for the successful delivery of future major capital projects such as being responsible for cost over runs, scope reductions, and implementation delays?

Response:

No. This information request provides no context in terms of the reason for the cost over-run, or the scope reduction or the implementation delay; in the absence of such context the response to a question such as this cannot be meaningful.

Generally, customers who receive service from the utility should be responsible for costs related to major projects that are prudently expended.

The question of responsibility for costs exceeding estimates is a broad issue that is beyond the scope of this proceeding. Very briefly, there will always be trade-offs between cost certainty (Commission approval late in the process and the transfer of all construction and implementation risks to a contractor) and lesser cost certainty which will result from Commission approval earlier in the process and earlier stage construction cost estimates. The occurrence of final costs of projects that exceed estimates, or scope changes, or implementation delays, does not of itself indicate that costs were imprudently occurred or that the utility should be held responsible for the variance between earlier estimates and the final cost.

16. Reference: Exhibit B-1, Page 7, Executive Summary – Earnings Sharing Mechanism

and below the allowed ROE, beginning in 2004. The PBR Agreement structure and the ESM were designed to encourage efficiencies over a longer term, and to enhance the speed and opportunity for pay back on investments in efficiencies from realized savings.

16.1. When improvements in efficiencies are made there is usually a requirement for an investment. Please identify for each investment made to improve TGI's operations whether or not the investment were capital investments (resulting in rate base increments) or operating investments (resulting in operating costs) or a mix and if so what was the percentage mix?

Response:

Please see response to CEC IR 1.2.2. Any investments required to realize the efficiencies are noted in the explanation provided in that response.

16.2. Please identify what costs & risks TGI's shareholder had with respect to undertaking efficiency projects and what costs & risks were carried by the customers?

Response:

The primary focus of the incentive structures in the 2004-2007 PBR Plan was to encourage TGI to seek efficiencies in the areas over which management had most control. The main categories in which to pursue such efficiencies were operating and maintenance expenses and base capital expenditures. The allowances for O&M and base capital used in the annual revenue requirements determinations during the PBR term were set on a formula basis and were not subject to rebasing (except for limited adjustments due to variations from forecast in the actual number of customer additions). The savings from efficiency gains relative to the formula-based allowances in both the capital and O&M categories were subject to 50:50 sharing via the Earnings Sharing Mechanism. On this basis it is fair to conclude that both the costs and risks of TGI's efficiency initiatives were shared equally between customers and the Company for the duration of the PBR.

16.3. How does the Earnings Sharing Mechanism distinguish between ongoing good management, which would not be shared and efficiency challenges beyond basic good management which might appropriately be shared or is there no such distinction?

Response:

The overall intent of the PBR Plan was to encourage TGI to seek operational and cost efficiencies while maintaining a high level of customer service through the use of service quality indicators. The starting point or base year for the PBR was the Commission's Decision on TGI's 2003 Revenue Requirements. In other words, the components of TGI's cost structure comprising the base year, including the levels of O&M and capital spending, had received a full review in an oral public hearing and regulatory process. The PBR Plan was established through a negotiated settlement process with intervenors and represented a balance of views and interests of NSP participants.

The PBR Plan formulas for O&M and base capital spending for TGI included productivity offset factors of 50% of CPI for two years and 66% of CPI for the balance of the PBR term that TGI had to absorb fully before efficiency gains greater than the productivity offset amounts were shared 50/50 with customers through the Earnings Sharing Mechanism.

The Earnings Sharing Mechanism itself does not distinguish between the sources of efficiencies achieved, whether through ongoing good management, or higher levels of efficiency achievement. While the PBR Plan and the Earnings Sharing Mechanism did not make explicit reference to these sources, TGI believes these concepts were clearly present in the overall structure and foundation of the PBR Plan. That the base year came out of a full public review by the Commission is evidence that the starting point for the PBR was sound. The productivity offset factors were, in effect, a dividend to customers that TGI had to exceed before receiving a 50% share of additional productivity gains. The service quality indicators and other PBR Plan features such as annual reviews provided assurance to customers that service was not being degraded for the sake of short term gain.

Please refer also to BCOAPO IR 1.31.1.

17. Reference: Exhibit B-1, Page 8, Executive Summary – PBR & ESM

Savings have been achieved in both O&M and capital expenditures, resulting in depreciation savings and rate base reductions. Total earnings available for sharing during the PBR Period are expected to be close to $138 million, of which an estimated $69 million benefit will have accrued to customers. Projected Gross O&M expenses of $195.1 million for 2009 are significantly lower than the 2003 Decision in real dollars ($204.7 million). This has been achieved despite the actual labour inflation during the PBR Period (approximately 3 per cent) being a full percentage point higher than the average Consumer Price Index ("CPI") from the Annual Reviews, which has been used to adjust to the real O&M expenses. This additional labour inflation has been absorbed through the productivity improvements and efficiency gains during the PBR Period. On a per customer basis, the efficiency gains achieved through O&M are even more significant, showing, in real terms, a decrease from $266 per customer in 2003 to $234 per customer in 2009.

17.1. Are savings achieved for O&M and Capital Expenditures rewarded in the same way or differently?

Response:

Savings achieved for O&M and capital expenditures as compared to the formula amounts included in rates impact the earnings sharing calculation differently. For example, if there is a $10 million savings in O&M and also a $10 million savings in capital in 2005, the impacts will differ. On a simplified basis, the O&M savings will result in $5 million pre-tax being returned to customers in that same year's earnings sharing calculation. The capital expenditures savings in 2005 would impact the earnings sharing calculation for all the remaining years of the agreement. Over the years 2005 to 2009 the $10 million savings would result in about $2 million being return to customers. The table below shows the illustrative calculation of the capital expenditure savings for each of the years, excluding any impact on the end-of-term capital incentive mechanism.

The impact of the capital savings on the sharing calculation is dependent on the timing of the expenditure, the depreciation rate, and the CCA class, so each specific expenditure would yield a different result.

	Amounts in $ thousands					
	2005	2006	2007	2008	2009	Total
Reduced depreciation expense (assume 3% rate)	-	(300)	(300)	(300)	(300)	(1,200)
Rate Base (Earned Return)	(381)	(726)	(695)	(682)	(404)	(2,888)
Total Pre-tax Sharing	(381)	(1,026)	(995)	(982)	(704)	(4,088)
Pre-tax Sharing at 50%	(190)	(513)	(497)	(491)	(352)	(2,044)

17.2. Are savings based on annual realized benefits or are they based on the present values of on-going benefits expected to be achieved?

Response:

The savings are based on annual realized benefits, with the exception of 2009 which is based on projections. The amounts do not represent present values.

17.3. Of the Capital Expenditure savings, how does Terasen know that TGI would not or should not have made the savings simply as part of the prudent management of the project?

Response:

Please refer to the response to BCOAPO IR 1.5.2.

17.4. Why is the 2003 Decision presented as the basis for comparison of O&M costs?

Response:

It is appropriate that TGI compare its O&M costs against the 2003 Decision. The 2003 Decision is the last year for which TGI had a full revenue requirement. The forecasts for that year were reviewed through an oral hearing, approved by the Commission, and serve to establish a baseline both for the formula O&M during the PBR period but also to establish the reasonableness of 2010 and 2011 O&M forecasts.

TGI has considered other benchmarks to compare the O&M costs, and has also incorporated those comparisons into the Application. On pages 159 – 177 of the Application, TGI presents a review of the actual O&M incurred for the years 2003 to 2009. On page 163, TGI compares very favourably to its peer companies in its O&M per customer. On page 347 of the Application, TGI demonstrates the 2010 and 2011 formula based O&M as a comparator. TGI also notes that comparing the forecasts to the O&M included in setting rates for any of the years 2003 to 2009 would yield a favourable comparison, and the same conclusion that the 2010 and 2011 forecasts included in the Application are reasonable and include only amounts required to operate the business and meet the needs or customers.

17.5. Were there any accounting changes during or just prior to the PBR period which would have caused additional expenditures to be capitalized during the PBR period as opposed to accounting policies in place for the 2003 Decision comparative period?

Response:

Changes in accounting policies prior to the PBR Period would have been reflected in the 2003 Decision that set the base for the calculation of the formula amounts. Changes in accounting policies during the PBR Period were discussed and reviewed at each year's Annual Review. The impacts of any of those changes on revenue requirements were accorded Exogenous Factor treatment. A summary of the GAAP changes that occurred and that had an impact on regulatory forecasts, are listed on page 198 of the Application. There were no GAAP changes that had a material effect on the capitalization of expenditures.

17.6. What was the average CPI increase during the PBR period?

Response:

The average CPI increase over the PBR period was 2.0%. The average net inflation that was used to derive the formula capital expenditures and gross O&M, which included the efficiency adjustment factor, was 0.78% over the PBR period.

17.7. Does the TGI experience of O&M being less than 2003 O&M inflated by CPI to 2009 mean that whatever the customer growth has been during the period TGI has absorbed that too?

Response:

In 2009 dollars, the gross O&M is about 4.5 per cent lower than the 2003 Decision amount, highlighting the efficiency gains achieved. The O&M per customer decrease of 12 per cent is significantly higher, highlighting those efficiencies even further by incorporating the impact of customer growth.

17.8. How does TGI's experience of absorbing labour cost increases (3%) above inflation (CPI%) compare with BC Hydro's budgeting practice and plan of incrementing budgets by customer growth and inflation less a planned productivity improvement?

Response:

The formulas for O&M and base capital expenditures in TGI's 2004 - 2007 PBR Plan (and two-year extension) include the same factors of customer growth, inflation and productivity offset. TGI has been using formulas for O&M expenditures with similar features in its revenue requirement applications since the mid-1990s. TGI has also used formulas for capital expenditures with similar factors in its 1998-2001 PBR. The O&M formulas have also had an allowance for exogenous factors to accommodate adjustments for uncontrollable cost items that were not in the base O&M. There have been some variations and some evolution of the O&M and capital expenditure formulas over time although the use of customer growth, inflation and productivity offsets as drivers has been a continuing feature throughout. Rebasing of the formulas using actual spending levels and experience, or test year results from a Commission Decision, has occurred several times since inception. TGI believes the formula-based approach in the context of its PBR Plans has provided sufficient flexibility to manage cost pressures such as labour cost increases by finding efficiencies in other ways. As is evident in the preamble to the question TGI has been able to deliver significant value to its customers under these ratemaking arrangements

TGI cannot speak to the effectiveness of BC Hydro's use of formulas in its O&M budgeting practices and revenue requirements applications although TGI understands that BC Hydro has adopted this approach recently. BC Hydro has not applied in any of its revenue requirement applications for any form of incentive regulation or PBR. A formula based approach for O&M or capital expenditures under a traditional cost of service (i.e. non-incentive based) ratemaking

model would have to be assessed over multiple revenue requirements applications to determine its value.

17.9. Does the phrase in the last sentence 'in real terms' mean inflation adjusted? (i.e. are the O&M cost per customer numbers provided in nominal dollars of the years or are these inflation adjusted dollars?)

Response:

The phrase "in real terms" means inflation adjusted, so that all amounts are stated in 2009 dollars.

18. Reference: Exhibit B-1, Page 9, Executive Summary – Customer Service Needs

Excellence in customer service requires not only satisfying SQIs today, but also being able to meet evolving customer needs and expectations as they arise. One area for improvement is in TGI's

18.1. Does Terasen see the evolving customer needs as strategic for its business (potentially requiring a redefinition of the business it is in from natural gas distribution to heat delivery) or tactical for its existing business (requiring response and innovation to continue satisfying customers)?

Response:

As has been demonstrated in the Application, we see the evolving needs as a strategic shift in how TGI will service customers longer term. We see that longer term, 20-40 years, TGI may see gas distribution as only a part of its energy delivery service and delivery of heat by other means a larger portion of its business.

18.2. Has Terasen identified all of the customer needs it sees evolving, if so please provide the listing of these needs and or any studies of customer needs Terasen has undertaken?

Response:

TGI has not identified all the customer needs it sees evolving as these customer needs are always changing and evolving and as such it is not possible to identify all needs. However, TGI continually surveys customers, including residential, commercial, industrial, builder developers and stakeholders to help understand what our customers want and desire. We also assess the marketplace for changes and trends, the economy and how it is affecting customers (as noted in the Forecasting section of the Application), and the municipal, provincial and federal policy landscape. It is from this that we then make business decisions and take steps to meet our customers changing needs. The requests with regards to Alternative Energy Solutions is an example of taking steps to meet customer needs. Please refer also to the IR response to the Return on Equity and Capital Structure Application CEC IR 1.19.1 appended below.

18.3. Has Terasen assessed each of the customer needs it sees evolving to determine the nature and size of the potential opportunity and to prioritize these opportunities for action by TGI?

Response:

See TGI's response to CEC IR 1.18.2. As TGI has determined a customer need and determined if it will respond by providing a service to meet the new need, it determines the potential opportunity. Depending upon the customer need and TGI's desired approach, the size of the opportunity and priority has been established. For example, internal work and analysis has been completed for Alternative Energy Solutions including Biogas, NGV and DES/Geo/Solar for the purpose of creating a strategic business direction/plan. The customer needs that have been identified and that are a priority traditionally result in applications to the Commission, such as this Application, the Customer Care and Enhancement Application, the LNG Dispensing Tariff Application, and the Piping to Suites Application, for example.

18.4. Has Terasen assessed each of these evolving customer needs to determine, which ones may represent opportunities for provision of additional chargeable service, which ones are integral to providing quality for existing services and which ones may represent new services altogether?

Response:

See response to CEC IR 1.18.2 and CEC IR 1.18.3. As customers needs are evaluated, and solutions arrived at, the next step is to determine if the solution should be one that should be charged as a separate offering or one that should be provided as part of the service for which they already pay delivery rates. For example, for NGV Compression Service and DES systems would have a separate rate for the provision of either compressed natural gas and heat. TGI has also determined that providing natural gas consumption information to customers (a growing need) should be provided as part of the existing service as it is integral to providing quality for existing services.

18.5. Terasen has identified three strategies for meeting customer needs (a) Customer Care Enhancement Project (b) Energy Efficiency & Conservation Programs (c) Alternative Energy Solutions Projects. Has Terasen identified other strategies or directions which it is not proposing at this time but is considering for the future or were these three the only strategies considered?

Response:

At this time the above three strategies and resultant applications are larger responses to meet current customer needs. Other smaller strategic responses and applications include:

- System Extension and Customer Connection Review Application
- Rate Schedule 16 – LNG Service
- Thermal Metering
- Piping to Suites
- Various Tariff Supplement Applications

As noted in the response to CEC IR 1.18.2, for instance, TGI constantly monitors and assesses the needs of customers and takes action where appropriate to meet these needs. During the course of such analysis, there are many strategies that are examined to meet a given need. However, only the preferred solution is brought forward to the Commission for approval.

18.6. For instance does Terasen see the multifamily dwelling market ('MFD') as a segment of customers with needs and what plans has Terasen developed and or been following with regard to capturing market share for MFD since TGI first experienced a drop in capture of MFD customers?

Response:

TGI has not seen a drop in MFD capture; rather, MFD new housing starts have increased compared to single family detached home starts and as such TGI's overall capture rate of customers is lower. TGI recognizes the Multifamily dwelling market as a segment of the overall residential market place with its own unique needs. TGI's focus has been on the decision makers in this segment such as builders and developers who ultimately determine the type of heating equipment to be installed. The focus has been on educating this group on the energy benefits of natural gas. At the same time TGI has been working at making the process easier and less costly to the developer. Examples of this work include changes to the main extension

test, TGI providing piping to the individual suites and providing flexible meter locations. See also the responses to CEC IR 1.10.10 of this Application and the IR responses to the Return on Equity and Capital Structure Application CEC IR 1.21.1, BCUC IR 1.37.1 and CEC IR 1.36.4 appended below.

Response from Return on Equity and Capital Structure Application CEC IR 1.21.1

21. Exhibit B-1 – Tab 1, Page 2 and 33 – Declining Capture and Declining Average Use

2) TGI's Ability to Attract and Retain Its Customer Base Is At Risk.

TGI is being negatively affected by two trends: TGI's declining rate of capture of the new construction market and the continued decline in annual use rates from existing customers.

This puts further pressure on natural gas as a fuel choice. Over the past five years, approximately two-thirds of all housing starts have been multiple units and Terasen's capture rate in this segment is currently only 18%.

21.1 What has Terasen done to enable it to capture the multi-family unit dwellings? Does Terasen have a cost effective solution for multi-family dwelling units?

Response:

TGI has made a concerted effort to increase capture of multi-family buildings over the last few years. The decision to use electricity versus gas is based on a number of factors. TGI's focus has been on builders and developers because they are the decision makers regarding heating choices in buildings. Terasen has focused on helping to educate this community on the benefits of natural gas (such as being the cleanest fossil fuel and is an efficient use of energy). At the same time TGI has been working at making the process easier and less costly to the developer. Examples of this work include changes to the main extension test, TGI providing piping to individual suites and providing flexibility in meter locations.

TGI continues to look at other innovative ways to serve this market by providing natural gas in combination with both energy efficiency and conservation ("EEC") programs and alternative energy solutions. Section C.3 of the 2010-2011 TGI Revenue Requirement Application ("Energy Efficiency and Conservation and Alternative Energy Solutions"), discusses these initiatives. TGI believes recent provincial energy policy (BC Energy Plan 2007) initiatives and changes to the British Columbia Utilities Commission Act (2008) have provided an impetus for enhanced and extended service offerings from TGI.

TGI believes that natural gas is a cost effective solution when all factors are considered; however, the fact remains that gas is challenged on a lifecycle cost basis but once other factors are considered such as, lifestyle, environmental benefits, etc. it can be a cost effective solution.

Please also see the response to BCUC IR 1.37.1.

Response from Return on Equity and Capital Structure Application BCUC IR 1.37.1

37.0 Reference: Exhibit B-1, Tab 1 p. 33 Business Risk

37.1 Please explain why TGI is only able to capture 18% of multiple unit construction? With the large margin between gas and Tier 2 RIB rates, does TGI anticipate improving its performance in the future?

Response:

There are a number of factors that influence TGI's capture rate of multi-family dwellings, including the installation costs, physical space requirements, operational costs, and of course the demand associated with the particular energy source.

The low capture rates experienced by TGI in the multi-family dwelling sector are a reflection of the behaviour exhibited by builders/developers, who in most cases choose to install electrical space heating equipment over natural gas. There are a number of factors that are influencing their decision, with the most significant being the higher capital and installation costs associated with natural gas space heating (as compared to electrical baseboards). Further, multi-family units are smaller than single family detached homes, and as such natural gas space heating in multi-family dwellings can be a more difficult installation. Lastly, in many cases it does not make sense for a developer to install gas heating appliances in individual suites as the heating equipment takes up valuable square footage that can be used for another purpose.

Developers tend to install equipment that they believe meets customer desires and provides the greatest margin, or return on developers investment. Though the Tier 2 RIB rate is in effect, we do not believe, and have not seen evidence that, the price spread between the Tier 2 Rate and gas rates is enough to translate into increased demand from end use customers to limit the use of electricity for heating applications. Secondly, due to the smaller size of multi-family dwellings compared to single family detached buildings, there is less electricity used to heat a multi-family unit and therefore, a smaller portion of the customer's electricity bill would be priced at the Tier 2 RIB rate.

Lastly, Developers are currently being encouraged by local policy to build projects that achieve some level of "green" certification, through rating systems such as LEED and Built Green. This results in additional construction costs to earn credits within the rating system to achieve the

certification. These rating systems allow certification to be achieved with electric baseboard heating. The developers then choose this lowest capital cost heating alternative to offset some of the additional related construction costs. The unintended consequences are more encouragement to install electric baseboard heating.

Due to these factors, a developer is currently still incented to install the lowest cost heating application (electricity), as the margin on an electrically heated home is higher than that of a gas heated home. TGI is certainly working towards improving its capture rates in this customer segment, and continues to maintain ongoing communications with the builder/developer community, promoting the use of natural gas and increasing awareness with regards to natural gas being part of the long-term solution to climate change. Since 2004, we have increased and refocused our sales staff to focus on the multifamily and vertical subdivision sector. Our sales staff have been focused on meeting with, and putting on workshops for builders, developers, architects and engineers to educate and influence the choice of heating applications. We have changed our main extension test and added an option to "pipe to the suite", both having been approved by the BCUC, to help ensure that gas remains a competitive option for both developers and end use customers.

However, absent formal policies in British Columbia which identify the right fuel for the right application at the right time and that specifically encourage end use gas applications, it is reasonable to assume that British Columbian's will continue to view natural gas as a fossil fuel that is contributing to the global climate change issues. It is also reasonable to assume the significant difference in installation costs between natural gas space heating and electrical baseboard heating will continue. Given this, it is reasonable to assume that even with the high level of marketing efforts we continue to provide, and also the margin between gas and Tier 2 RIB rates, only marginal increases to capture rates for multi-family dwellings will occur.

Response from Return on Equity and Capital Structure Application CEC IR 1.36.4

36. Exhibit B-1 – Tab 1, Page 32 – Declining New Customer Capture Rate

A utility's ability to manage risk is in part dependent on its ability to attach and retain customers. These factors are a significant influence on the throughput volume that will flow across the utility's distribution system over the long term and will have a major effect on the long-term ability of the utility to recover its investment. In TGI's case, the Company is capturing a declining percentage of the new housing starts in BC, TGI is also experiencing declining use rates for existing customers. These factors were occurring even before the provincial Energy Plan was announced, which has a strong focus on energy conservation, and therefore, this trend can reasonably be expected to accelerate.

36.4 What strategies is Terasen using to capture multi-family dwellings? What strategies are working?

Response:

The Terasen Utilities have three regional sales teams focused primarily on maximizing natural gas use in residential new building construction. Our primary target is space and water heating, followed by lifestyle applications like fireplaces, cooking, barbeques, dryers, etc.

We have primarily been focused on the Multi-family dwelling business, understanding that this form or housing has an appeal to first time home buyers, and as demographics change, for those interested in downsizing. This building type has also recently found favour with municipal planners interested in increasing urban density as a strategy in support of greener communities.

Our focus in this market begins at the planning stage with architects, engineers and builders/developers ("AEDs"). Generally through our contacts in the industry, we are aware of plans prior to the building permit stage, and have an opportunity to influence fuel choice. We have developed special products targeted specifically at this market as well (vertical subdivisions, piping-to suites, and thermal metering being recent examples). Early influence and special products can make a difference in fuel choice, but electric baseboards remain the heating source of choice for entry level and low price point consumer markets.

Recently, we have been successful in working with AEDs on hybrid solutions – combining gas requirements with renewable heat sources like geo-exchange and waste heat recovery. These hybrid solutions are perfect examples of how traditional gas utility service offerings must evolve to include alternative energy sources to optimize value for our customers, while minimizing the carbon footprint of the building. Hybrid solutions will form a fundamental service offering for the Terasen Utilities in this market now and into the future.

18.6.1. If there are plans, when were they put in place and what has been the company's quantitative experience with regard to achieving continuous improvement and operational excellence in implementing them?

Response:

TGI believes that as is demonstrated by the submission of this Application, the Customer Care Enhancement Project Application and applications such as Thermal Metering, Piping to Suites, Energy Efficiency and Conservation and LNG Tariff 16, that TGI is striving to meet the evolving customer needs as they arise. As noted in response to CEC IR 1.18.6.2, TGI believes that it is meeting its definition of operational excellence with respect to MFD's, and that TGI regularly

evaluates its progress in trying to improve on its capture rate of MFD's. Through this continuous improvement, TGI alters and adapts plans to in pursuit of increasing the capture rate for MFD. In other words, TGI continues to plan, evaluate and adapt as the market changes so as to meet customer needs.

18.6.2. Does TGI believe that its past performance with respect to capturing MFDs has demonstrated operational excellence?

Response:

On page 5 of the Application, TGI states: "For Terasen Gas, Operational Excellence means the prudent combination of service quality to our customers, and the cost of providing those services, while ensuring employee and public safety, and operating in an environmentally responsible manner". Given this statement, TGI believes that its past and current performance with regards to capturing MFD's represents operational excellence. TGI is providing service quality to this customer segment, in a safe and environmentally responsible manner. TGI intends to continue to perform in a manner that it considers Operational Excellence in this area as noted in response to CEC IR 1.18.6.3.

Note that TGI believes that it could also improve the capture rate of MFD and detached home capture rates. As noted in response to CEC 1.18.6.2, TGI recognizes that there are many factors that developers must consider when developing housing and TGI must therefore continue its efforts at increasing capture rate of MFD's and detached home housing starts.

18.6.3. What would TGI consider as a capture rate target for MFDs which would represent operational excellence?

Response:

As was noted in response to CEC IR 1.18.6.2, TGI already considers that its approach to MFD's represents operational excellence, as it defines the term. TGI does not consider the actual capture rate for MFD's defines operational excellence .

However, as with all sectors, TGI continues to work at providing solutions (both gas and alternative energy) that would increase the capture rate in MFD's and other markets. As noted in response to question CEC IR 1.18.7.2, there are many factors that a developer must take into account when constructing MFD's and gas, or energy choice, is only one factor. Depending

upon the end use buyer (age, income, and location), size of the unit, and the developers desired ROI, a developer must make a choice for what type of energy sources will be in the development as well as what other aspects of the development will help achieve those goals. As such TGI will continue its efforts to increase the capture rate for this market.

18.7. For instance Terasen has made the point that its competitiveness with electricity requires taking into account the customer capital cost investment in a furnace versus the electric resistance heating base board. Has Terasen been looking for solutions to this problem and if so what has it been considering?

Response:

An ongoing concern for TGI is that the capital cost of electric baseboard heating is less than a natural gas fuelled heating system. In response, TGI focuses on post-construction benefits of gas heating, including:

- Promoting high-efficiency gas fired equipment to minimize energy costs.
- Emphasizing to builders and consumers the lower energy costs (especially when high-efficiency gas appliances are installed).
- Emphasizing that with forced-air gas furnaces there is the added benefit of air movement within the dwelling which promotes health and comfort.
- Educating customers, developers, architects, engineers, policy makers and stakeholders as to the use of the right fuel at the right time and the right place.
- Promoting the concept of using alternative energy in combination with natural gas. Unlike an electric baseboard space heating system, a natural gas fuelled heating system has the potential to be readily teamed with other energy sources (i.e. solar), be linked to the heating of domestic water; and also, be part of a district energy system that could utilize surplus heat from a nearby heat source (i.e. refrigeration plant).

18.7.1. Has Terasen examined the possibility of one furnace for two or four homes with heat distribution to the homes instead of natural gas distribution to the homes?

Response:

Yes. This technology is referred to as "district energy" and works well in conjunction with thermal metering, which measures the amount of heat used by the end user or end users.

District energy usually employs a liquid as the heat-carrying medium; however, depending upon building design, air could be an alternative heat-carrying medium although this is not as common. District energy technology can be especially viable as a means of using otherwise wasted heat from a nearby heat source (i.e. ice arena refrigeration plant). One of the advantages of district energy, however, is economies of scale. It is relatively uncommon for district energy systems to be designed for only 2-4 homes as the capital costs of such a strategy would not necessarily be cheaper than that of a one furnace/one house strategy. Further, it is more rare to see developments of only 2-4 houses. As such it is still more typical to see a single heat generating source for each individual house until the scale of a DES system is larger than a few houses.

18.7.2. Would there be potential savings in service connections, furnace costs and space utilization?

Response:

The question is describing a "district energy" system, as discussed in the response to CEC IR 1.18.7.1. There is a potential opportunity for savings in service connections, furnace costs, and space utilization with a "district energy" space heating system. However, depending upon the site-specifics, those cost savings may be offset or more than offset by the cost of additional piping and related infrastructure associated with that technology. The cost effectiveness of "district energy" retrofitting must be considered on an individual basis, and the most effective "district energy" installations are typically those where a group of intended buildings in a community are designed from a "district energy" perspective. Please also refer to the IR response to the Return on Equity and Capital Structure Application, CEC IR 1.36.6, appended below.

Response from Return on Equity and Capital Structure Application CEC IR 1.36.6

36. Exhibit B-1 – Tab 1, Page 32 – Declining New Customer Capture Rate

A utility's ability to manage risk is in part dependent on its ability to attach and retain customers. These factors are a significant influence on the throughput volume that will flow across the utility's distribution system over the long term and will have a major effect on the long-term ability of the utility to recover its investment. In TGI's case, the Company is capturing a declining percentage of the new housing starts in BC, TGI is also experiencing declining use rates for existing customers. These factors were occurring even before the provincial Energy Plan was announced, which has a strong focus on energy conservation, and therefore, this trend can reasonably be expected to accelerate.

36.6 Does Terasen have a view with respect to the economics of hydronic distribution of heat in multi-family dwellings versus conditioned air circulation in multi-family dwellings versus natural gas distribution to each dwelling unit?

Response:

As noted in response to question IR CEC 1.35.3, the economics of a hydronic heat distribution to multifamily dwellings versus air conditioned circulation versus natural gas distribution to each dwelling are dependent upon each individual project and the variables inherent in those projects. In some projects it may be more or less economic for each of the technologies identified.

However, there are far more options than those noted above that are considered for a multifamily development and in many cases could include a combination of all three of hydronic heating, conditioned air and gas distribution to each dwelling for every unit in a building. For example, there are some buildings which have a central gas fired boiler for space heat, separate cooling and natural gas separately metered and delivered to each suite for appliances such as fireplaces, cook tops, barbeques and hot water heaters. Some of the additional options and considerations that affect the economics of providing heating and cooling to a multifamily development include:

- *Building Type – Different building type will lead to different heating and cooling options.*
  - *Wood frame up to 6 stories high depending on fire rating.*
  - *Concrete Tower type 6 stories to 60 plus stories.*

- *Target Market – depending upon the target market, a developer will install different equipment to maximize return on investment.*
  - *Low end, entry level.*
  - *Mid end*
  - *High end Luxury*
  - *Resort, seniors housing, intermediate care, traditional residential;*

- *Region and Associated Customer Requirements – Different regions have different requirements and customer tastes.*
  - *Vancouver Island and Lower Mainland - small suite footprint, low cost no air conditioning, electric fireplaces, some lifestyle gas including - ranges, barbeque, dryers, fireplace;*
  - *Interior - larger suite footprint, air conditioning is required. Higher gas loads in mid and high end market.*

- *Types of Gas Fired System – There are many types of gas fired systems that can be selected by a developer.*

- *Central Applications*
  - *Hot water heating - Central boiler piped supply and return to suites from a central mechanical room to radiators, convectors or slab heating in the suite. No cooling;*
  - *Water Loop Heat Pump Heating and Cooling. (WLHP) - Ideal if there is a commercial space on main floor. Very cost effective. Boiler and cooling tower create ideal temperature conditions 60 to 100 F for individual heat pumps in suite or commercial space.*
- *Individual Suite applications*
  - *Furnace - Condensing furnace contained in suite utility room provides heating or cooling through a ducted system.*
  - *Combination System - Dual function hot water tank provides heating hot water to a coil in a fan coil. Both located in the utility room of the suite. Can provide cooling by either central chilled water system or by DX cooling application. Power vented application;*
  - *Wall Pak - Provides heating or cooling through a ducted system to the suite. Sits on the outside wall of the suite usually in a small room on the outside deck.*

- *Alternative Energy Options – depending upon end use customer target market, a developer may choose to supplement, or replace, gas and electricity usage with alternative energy. Options include:*
  - *Ground Source Heat Pump*
  - *District Energy Systems*
  - *Air Source Heat Pump*
  - *Solar Thermal*

In other words there are a significant number of options that can be considered for a multi-family development, each with its merits, and each option will drive an economic result that the developer must consider. Our sales staffs help developers determine the costs and the benefits energy usage in each individual project in the hope of determining the optimal energy solution for meeting both economic thresholds but also energy efficiency and emissions reduction targets.

18.8. For instance has Terasen looked at the potential for heat loss recovery and recirculation systems for homes and businesses?

Response:

Yes. Heat recovery ventilation systems have been readily available for many years and TGI has been promoting the use of this equipment. Drain waste water heat recovery technology is also readily available and is promoted by TGI. With respect to building recirculation systems, TGI encourages developers to design building space heating systems to circulate air to promote even heat throughout the structure. This strategy increases occupant comfort and reduces the heating of otherwise cooler areas within the building.

19. Reference: Exhibit B-1, Page 10, Executive Summary – Alternative Energy Solutions

Indeed, the majority of BC municipalities have committed to the provincial government to become carbon neutral by 2012. This obligation will be reflected in local bylaws and thus change 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 critical.

19.1. To what degree does Terasen believe municipalities have experience with energy planning and to what degree does Terasen have experience with alternative energy solutions? How will this partnership proceed to derive and deliver quality solutions for customers?

Response:

In the recent past, energy planning has been the responsibility of utilities, mainly through Resource Planning and DSM initiatives. With the exception of municipalities that own energy utilities, municipalities appear to have varying degrees of experience and capacity in this area. Larger municipalities may have staff dedicated to understanding energy use and reduction potential. Smaller communities add this responsibility to others that existing staff may have. Many communities have BC Hydro funded Energy Managers on a temporary basis to gain an understanding of electric energy conservation potential and planning. It is clear that an approach involving the community, utilities and business, as proposed by QUEST, will lead to optimal energy planning. This type of collaboration is in its infancy. Utilities are making progress in working and through collaboration with municipalities, perhaps on a formal basis through similar MOU's, utilities can use their Resource Planning expertise to help municipalities in this area .

Terasen Gas' Technical Sales and Support team has been assisting our sales group with technical questions from customers regarding alternative energy systems since this technology became feasible and marketable, even before the provincial government's climate change initiatives increased the focus on these alternatives. Our sales staff have helped customers design and implement alternative energy systems in many new developments. TGI staff also participates with other alternative energy experts at conferences, and on committees and steering groups brought together to bring alternative energy systems to mainstream use.

After initial contact, partnerships generally proceed with Memorandums of Understanding that outline, in general terms, the working relationships and obligations between a community and TGI. A feasibility study will follow, after which definitive agreements will be signed before TGI funded construction takes place. TGI proposes to own and operate Community energy systems within municipalities, built and operated to TGI's proven operating standards. There may be

several partnership models to consider that would be customizable to a particular municipalities needs and interests. Generally these working relationships would seek first to improve the efficient use of all energy, including natural gas, through appropriate and timely energy efficiency and conservation initiatives, followed by the prudent application of renewable energy systems, then gas and electric "grid" energy as required for peaking and lifestyle requirements. Throughout the derivation and delivery of quality solutions, TGI will continue to apply principles of "direct use" of energy, especially gas for space heating and hot water, supplementing the practical application of renewable energy as required.

19.2. Does Terasen have a perspective on the types of local government planning and local bylaws it would like to see developing within the municipalities?

Response:

TGI currently supports the guiding principles for energy planning included in the QUEST model. We would encourage local government planning and bylaws to support these guiding principles with due consideration for the requirements and needs of the community. TGI staff also participates with other alternative energy experts at conferences, and on committees and steering groups brought together to bring alternative energy systems to mainstream use, including committees determining revisions to, or new regulations, codes and standards as required to further the provincial governments climate action initiatives.

19.3. To what extent does Terasen believe that the provincial government will play a role in shaping energy planning in local communities?

Response:

The provincial government, through its various policy and "carbon lean" legislation and targets, is already shaping the future of energy focus and planning within communities. This role can and should continue as it provides the necessary strategic framework from which the municipalities can then implement their own policies and bylaws, which in turn will help the Province be successful in achieving its climate change goals, objectives, and commitments.

20. Reference: Exhibit B-1, Page 11, Executive Summary – Alternative Energy Solutions

geographic footprint, skilled workforce, knowledge and experience. Our customers' interests are best served by Terasen Gas being - and being perceived by municipalities and communities as - a provider of solutions for natural gas and/or alternative energy delivery.

customers. We believe that it is in the interest of both existing and future customers that Terasen Gas not only be able to offer these services, but that the programs, development and sales costs of these activities for the forecast period form part of the costs to be recovered from customers as part of this RRA .

20.1. How are Terasen's customers' interests best served by being and being seen as a provider of alternative energy solutions?

Response:

As noted in the Application on pages 201 to 204, TGI believes that the pursuit of both alternative energy and gas is good for both existing and new customers. Existing customers benefit from the costs that alternative customers pay to offset overhead costs, and by the addition of new gas customers to the system which will result in the system being used more efficiently. New customers benefit because they will now be able to select the option that best meets their needs, be that gas, alternative energy, or a combination of both. Society benefits because of the energy efficiency of these options and the reduction in emissions. For these reasons, TGI believes that it is incumbent upon the Company to pursue both gas and alternative energy options. See also the responses to BCUC IR 1.19.1, 1.23.1.1, and 1.24.4 for additional discussion.

With respect to "being seen as a provider", TGI believes that customer perceptions will drive customer behaviour. In response to BCUC IR 1.23.1.1, interviews with customers in the TNS Canadian Facts report demonstrated the belief that Terasen Gas should provide customers with solutions for energy efficiency which includes alternative energy. In fact, some comments from customers in the report indicate that they believe that gas will cease to exist as an energy option in at some point in the future. Further, in the report customers believed that TGI should take a role in leading this change. This is further echoed in customer survey performed by Ipsos Reid as part of BCUC IR 1.23.1.1. It is critical to ensuring that TGI continues to attract and retain customers that TGI is seen as addressing these customer perceptions by providing customers with solutions to reduce energy usage and, over time, move to lower emission energy sources. TGI also believes it is important from a corporate perspective to play a leading role in the evolution of the energy marketplace.

20.2. Are each of the alternative energy solutions Terasen plans to offer economic and competitive for customers, with respect to both natural gas and electricity as alternatives now and for the very long term?

Response:

Please see the response to CEC IR 18.7.2. For each of Solar, Geo-exchange and DES systems a cost of service type of analysis is performed to determine the revenue requirement of the service provided. From that, a levelized rate is determined. This is presented to the customer who then must decide if they wish to enter into a contract to pay for the service. If they do so, the customer has made the choice that the service is economic. If they do not wish to enter into a contract for the price derived from the analysis and, for arguments sake, there are no changes that can be made to the service to lower the revenue requirement resulting in a price the customer is willing to pay, then TGI would not provide service to the customer. From that standpoint, every development is economic as a customer is willing to pay for the service.

Whether or not the price is competitive compared to gas and electric is a separate discussion. As noted in appended response to the Return on Equity and Capital Structure Application CEC IR 1.36.6 (appended to RRA CCE IR 18.7.2), every project will result in a different solution and therefore will have different costs. The best knowledge at the time will be used to compare both traditional energy options such as electricity and gas with that of the alternative. In many cases these alternative solutions are competitive with electricity or gas over time. While there will always be a degree of uncertainty as to which is the lowest cost option at any particular time, TGI believes that alternative and traditional energy form costs are converging.

However, from a customer standpoint whether or not the price for alternative energy is similar to gas and electric pricing is not always the driving consideration as developer construction decisions are based upon the ability for the developer to sell a product (in this case a home). If the developer can sell a home faster or with a higher margin with alternative energy than without, they will do so. The end use buyer has then made a decision to pay the cost of alternative energy instead of gas or electric and in doing so confirms that the price is competitive.

20.3. Why has Terasen rejected the Non-regulated Utility Model in favour of the Utility model?

Response:

Please see the response to BCUC IR 1.24.4.

21. Reference: Exhibit B-1, Page 12, Executive Summary – Projected Rate Increases

To implement these increases, TGI proposes that the basic charge and administration fees be held at existing approved 2009 levels and that the volumetric and demand based delivery rates be adjusted to recover the revenue requirement increase in 2010 and 2011. TGI believes that this proposal is consistent with the 2007 BC Energy Plan Policy Action Item 4, which called on utilities to implement innovative rate designs. TGI believes this rate design supports its energy efficiency efforts and meets the evolving expectations of customers.

21.1. What would be the effect of applying the rate increase to the 'basic charge' the 'administration fees' as well as to the volumetric and demand delivery rates?

Response:

The effect of applying the rate increase to the basic charge and the administration fees, as well as the volumetric and demand delivery rates, is that all rate components would increase by an equal percentage of approximately 5.6% in 2010 and an additional 4.4% in 2011; correspondingly, the volumetric and demand delivery rates would decrease from what has been proposed in the Application.

A change in the allocation to the various delivery rate components will not affect the proposed annual bill impacts or the proposed revenue collected from each Rate Schedule because the allocation of the revenue deficiency to each Rate Schedule is not impacted by this change. The revenue deficiency allocated to each Rate Schedule will remain as presented in Schedules 22-25, column 8 in Section C, Tab 13.

21.2. Please provide a table by rate class comparing the application to rates, which Terasen has proposed to the alternative of across the board application

Response:

Please refer to the table on the following page.

	2010 as Proposed				2010- Past Practice				Rate Difference			
	Basic Charge ($/Month)	Administration Fee ($/Month)	Delivery Charge ($/GJ)	Demand Charge ($/GJ)	Basic Charge ($/Month)	Administration Fee ($/Month)	Delivery Charge ($/GJ)	Demand Charge ($/GJ)	Basic Charge ($/Month)	Administration Fee ($/Month)	Delivery Charge ($/GJ)	Demand Charge ($/GJ)
RS 1- Residential	11.840	-	3.213	-	12.500	-	3.126	-	(0.660)	-	0.087	-
RS 2- Small Commercial	24.840	-	2.667	-	26.220	-	2.617	-	(1.380)	-	0.050	-
RS 3- Large Commercial	132.520	-	2.282	-	139.890	-	2.255	-	(7.370)	-	0.027	-
RS 4- Seasonal[1]	439.000	-	0.838	-	463.410	-	0.804	-	(24.410)	-	0.034	-
RS 5- General Firm	587.000	-	0.635	15.690	619.640	-	0.626	15.470	(32.640)	-	0.009	0.220
RS 6- Natural Gas Vehicles	61.000	-	3.600	-	64.390	-	3.587	-	(3.390)	-	0.013	-
RS 7- General Interruptible	880.000	-	1.057	-	928.930	-	1.045	-	(48.930)	-	0.012	-
RS 22- Large Industrial T-Service	3,664.000	78.000	0.778	17.000	3,867.720	82.340	0.774	17.000	(203.720)	(4.340)	0.004	-
RS 22A- Large Industrial T-Service[2]	4,810.000	78.000	12.496	17.000	5,077.440	82.340	12.419	17.000	(267.440)	(4.340)	0.077	-
RS 22B- Large Industrial T-Service[2]	4,537.000	78.000	7.946	17.000	4,789.260	82.340	7.913	17.000	(252.260)	(4.340)	0.033	-
RS 23- Large Commercial T-Service	132.520	78.000	2.282	-	139.890	82.340	2.255	-	(7.370)	(4.340)	0.027	-
RS 25- General Firm T-Service	587.000	78.000	0.635	15.690	619.640	82.340	0.626	15.470	(32.640)	(4.340)	0.009	0.220
RS 27- General Interruptible T-Service	880.000	78.000	1.057	-	928.930	82.340	1.045	-	(48.930)	(4.340)	0.012	-

	2011 as Proposed				2011- Past Practice				Rate Difference			
	Basic Charge ($/Month)	Administration Fee ($/Month)	Delivery Charge ($/GJ)	Demand Charge ($/GJ)	Basic Charge ($/Month)	Administration Fee ($/Month)	Delivery Charge ($/GJ)	Demand Charge ($/GJ)	Basic Charge ($/Month)	Administration Fee ($/Month)	Delivery Charge ($/GJ)	Demand Charge ($/GJ)
RS 1- Residential	11.840	-	3.413	-	12.950	-	3.239	-	(1.110)	-	0.174	-
RS 2- Small Commercial	24.840	-	2.814	-	27.170	-	2.712	-	(2.330)	-	0.102	-
RS 3- Large Commercial	132.520	-	2.397	-	144.950	-	2.336	-	(12.430)	-	0.061	-
RS 4- Seasonal[1]	439.000	-	0.897	-	480.180	-	0.833	-	(41.180)	-	0.064	-
RS 5- General Firm	587.000	-	0.668	16.504	642.060	-	0.649	16.030	(55.060)	-	0.019	0.474
RS 6- Natural Gas Vehicles	61.000	-	3.754	-	66.720	-	3.717	-	(5.720)	-	0.037	-
RS 7- General Interruptible	880.000	-	1.110	-	962.540	-	1.083	-	(82.540)	-	0.027	-
RS 22- Large Industrial T-Service	3,664.000	78.000	0.813	17.000	4,007.680	85.320	0.802	17.000	(343.680)	(7.320)	0.011	-
RS 22A- Large Industrial T-Service[2]	4,810.000	78.000	13.071	17.000	5,261.180	85.320	12.869	17.000	(451.180)	(7.320)	0.202	-
RS 22B- Large Industrial T-Service[2]	4,537.000	78.000	8.296	17.000	4,962.570	85.320	8.199	17.000	(425.570)	(7.320)	0.097	-
RS 23- Large Commercial T-Service	132.520	78.000	2.397	-	144.950	85.320	2.336	-	(12.430)	(7.320)	0.061	-
RS 25- General Firm T-Service	587.000	78.000	0.668	16.504	642.060	85.320	0.649	16.030	(55.060)	(7.320)	0.019	0.474
RS 27- General Interruptible T-Service	880.000	78.000	1.110	-	962.540	85.320	1.083	-	(82.540)	(7.320)	0.027	-

[1]Delivery charge reflects the off-peak period
[2]Delivery charge reflects firm DTQ

22. Reference: Exhibit B-1, Page 13, Executive Summary & Page 16, Introduction – Accounting Changes

The major contributor to the forecast revenue deficiency in 2010 and 2011 is mandatory changes to accounting standards. The most significant of these accounting standard changes are:

- reductions in the amount of overheads capitalized; and
- increases in depreciation expense.

These two items, in aggregate, account for a cumulative impact of $42.9 million in 2010 and $43.4 million in 2011. Accounting changes also impacted the forecast gross level of O&M expenses, as has the introduction of new codes and regulations and changes to government policy. In total, these three factors have contributed to an increase in the 2010 revenue requirements of $2.8 million and $4.5 million in 2011. But for these changes, the cumulative revenue requirement outlined in this Application of $27.9 for 2010 and $49.8 million for 2011 would have been a revenue surplus of $17.8 million in 2010, and a deficiency of $1.9 million in 2011. (Page 13)

The requested rate increases for 2010 and 2011 are being driven by the significant changes taking place in TGI's external operating environment. The single largest contributor to the requested rate increase, for instance, is accounting changes associated with the adoption of new accounting standards applicable to TGI. But for the accounting changes, the revenue requirement would have indicated a rate decrease for 2010 and a small increase for 2011. (Page 16)

As discussed in Part III, Section C, Tab 11 Accounting and Other Policies, IFRS requirements allow only directly attributable overhead to be capitalized. Terasen Gas has completed a study of overheads capitalized under IFRS guidelines, which has resulted in a decrease in the overheads capitalized rate from 16 per cent of adjusted Gross O&M to 8 per cent of Gross O&M. The impact of this on revenue requirements is a decrease in overheads capitalized and resulting increase in revenue requirements of $11.2 million. This impact is offset in both years by increased capitalized overhead on higher gross O&M (2010 impact is $1.2 million with an additional impact in 2011 of $0.7 million). (Page 223)

The current study indicates an 8 per cent overhead capitalization rate as applied to gross O&M is appropriate. While this is significantly below the effective overhead capitalization rate of 13.8 per cent currently approved in rates, it is consistent and within a suitable range compared to the original Terasen Gas recommendation of roughly 10 per cent proposed in the 2003 Revenue Requirement Application. Contributing to the

decrease from the 10 per cent overhead rate recommended by the prior study is exclusion of specific costs as a result of IFRS. Excluded costs from overhead capitalized include training activities, project investigation and approval activities, and those activities that are more general administration in nature. (Page 490)

22.1. Please confirm that the overhead capitalization change being proposed by Terasen is responsible for about 2% of the 5.3% rate increase on the delivery in 2010 and none in 2011 because the change creates a onetime impact on revenue requirements provided that the capital plan remains about the same size. Because the capital expenditure plan increases going from 2010 to 2011 there is presumably some small impact in 2011 as well. Please confirm this and refine the percentages of rate increase attributable to the change to overhead accounting.

Response:

On its own, the change in the overhead capitalization rate and methodology is responsible for approximately 2% of the 5.3% rate increase on the delivery rate in 2010. The change in the rate and methodology has a one-time impact in 2010 as compared to 2009, but when comparing 2011 to 2010, there is no incremental impact of this change. As displayed in Table C-2-1 and discussed more fully on Page 493 of the Application, the total changes in overheads capitalized and their contribution to the 5.3% increase are also summarized in the following table. Note that the amount of overheads capitalized is not dependent on the level of capital expenditures, but instead on the amount of gross O&M, since it is calculated as a percentage of O&M.

Overheads Capitalized Impact on Revenue Requirement Changes

Amounts in $ millions	2010	Incremental 2011	Cumulative 2011
Methodology and rate impact	11.2	-	11.2
Rebasing impact	1.3	-	1.3
Change in gross O&M impact	(1.2)	(0.7)	(1.9)
Total	11.3	(0.7)	10.6
Impact on rate increase			
Methodology and rate impact	2.1%	0.0%	2.1%
Rebasing impact	0.2%	0.0%	0.2%
Change in gross O&M impact	-0.2%	-0.1%	-0.4%
Total	2.1%	-0.1%	2.0%

22.2. Given the expressed importance and magnitude of the impact of TGI's proposed changes to its overhead capitalization rates and depreciation rates it will be important to determine if the accounting rules for application are tight and determinative or whether there is an element of judgment as to how they are applied. Is Terasen confined by tight and determinative rules or has it applied judgment to determine the overhead capitalization rate and or the depreciation rates?

Response:

IFRS applies broad principles that do have interpretation in their application, rather than tight or specific rules, consistent with the approach taken in Canadian GAAP. Terasen Gas believes that we have correctly interpreted and applied the principles set out in the IFRS standards for both overheads capitalized and depreciation. Terasen Gas has been part of working groups across both the Fortis organization, and industry specific working groups like the Canadian Gas Association and the Canadian Electrical Association. Additionally, the Company has consulted with other regulated companies in the province. In these consultations with other regulated companies, many of our peers are also reaching similar conclusions around both overheads capitalized and depreciation. Terasen Gas, in conjunction with the other regulated companies in the province, issued the report, *International Financial Reporting Standards: A Summary of the Anticipated Impacts of Transition to IFRS on Rate Regulated Utilities in British Columbia* (attached as Appendix H-1 of the Application). The proposals TGI has put forth in the RRA dealing with IFRS implementation are consistent with the options identified in this report.

22.3. Does Terasen believe that the cost of an asset capitalized on to its balance sheet and into its rate base should be the same if it is provided from outside the company or from inside the company, all else being equal?

Response:

The mix of capital work that is performed in house versus contracted out can change from year to year. For work that is contracted out, the entire amount paid to the contractor is generally capitalized. For in house work, TGI follows GAAP to determine what items are eligible for capitalization. Therefore, depending on whether work is done in house or externally, there may be differences in the components that make up what is eventually capitalized. TGI is required to follow GAAP (whether Canadian or IFRS) in its capitalization policies regardless of whether these policies are consistent with the policies followed by contractors.

22.4. If Terasen were to sell assets it had constructed does it believe that it should collect in the price it obtains for all of the direct and indirect costs contributing to that construction including all associated overheads or does it believe that it need not collect in the price for some of the overheads?

Response:

TGI is not in the business of constructing assets for immediate sale. However, if Terasen Gas were in the business of selling assets it had constructed upon completion, the Company would look to recover the costs incurred to construct those assets, both direct and indirect, including the gain (or loss) realized on the sale of those assets. If Terasen Gas had constructed an asset for its own use, and at a later date, were to sell the asset the price would consider the remaining useful life of the asset and Terasen Gas would expect to receive at a minimum, the remaining book value of the asset, which would reflect the undepreciated costs, both direct and indirect, that were incurred in constructing the asset.

23. Reference: Exhibit B-1, Page 20, Part II Introduction – PBR

TGI must invest to maintain Operational Excellence.

- The Company has exhausted opportunities for significant incremental efficiency gains under the existing PBR framework. The current PBR Agreement has an efficiency factor equal to two-thirds of inflation, an implicit productivity improvement that is not sustainable, especially when labour inflation is higher than inflation rates.

- Expenditures that were pragmatically deferred during the PBR Period cannot be deferred indefinitely and some will need to be made in the 2010/2011 forecast period. TGI must continue to invest in the integrity and reliability of the energy delivery system. To ensure ongoing compliance to existing codes and anticipated new or changed codes, additional O&M funding is required.

23.1. Please provide Terasen's views as to what would be a sustainable rate of productivity increase for the company?

Response:

TGI interprets "rate of productivity increase" to be a reference to an efficiency factor akin to that employed in the PBR period. A reasonable level of productivity increase would vary depending on the year and the circumstances. For the forecast periods of 2010 and 2011, a sustainable level of productivity increase would be zero, since TGI is coming out of a period of time where we achieved significant productivity gains, which are not sustainable at this point in time due to significant changes in the external operating environment.

23.2. Please list and quantify all the expenditure items which were pragmatically deferred during the PBR period and which will now have to be spent in the years to come?

Response:

Please refer to responses to BCUC IR 1.75.1 and BCUC IR 1.77.1.

23.3. Please identify any integrity and reliability issues for the energy delivery system which were identified during the PBR period but have not required investment or expenditure yet and can adequately be handled sometime in the future?

Response:

When determining the 2010-2011 funding requirements, a risk based approach is used to prioritize integrity and reliability issues. Any low risk items that could be adequately handled in the future have been deferred and are not represented in the O&M funding request.

23.4. Please identify any codes and standards for which Terasen was not fully compliant during the PBR period and for which additional O&M funding is or will be required?

Response:

Unregistered pressure vessels are the only instance where Terasen Gas was not fully compliant with external codes and standards. Commencing in 2005 a program was initiated to identify line heaters that would provide higher efficiency and lower emissions than the atmospheric boilers in use at that time. As a result a number of Viessman boilers were installed to replace the older units and increasing the combustion efficiency from the 60-70% range to higher than 90%.

The regulations specific to the registry of boilers and pressure vessels are complex and require a level of expertise to interpret. In 2009, Distribution Asset Management replaced their Operations & Maintenance Manager with a Professional Engineer who is also a registered boiler and pressure vessel inspector. As the new manager became acquainted with the natural gas distribution system he identified the non-compliance with the applicable code regarding the Viessman boilers. This had not been previously identified by the contractors who installed the systems.

The failure to register the boilers has had no effect on the safety of the public or the plant nor the ongoing reliability of service. The chief boiler inspector of the BC Safety Authority has been advised of the situation. However, with the non-compliance identified Terasen Gas has an obligation to correct the issue and an additional $50k has been requested in 2010 and 2011 to fund an audit of the existing boilers and pressure vessels, to develop and implement appropriate maintenance programs and to complete all requirements to bring these assets into full Code compliance.

24. Reference: Exhibit B-1, Page 44, Part III Section A Tab 1 – GHG Goals

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.

The targets for industrial greenhouse gas emissions are as follows:

24.1. With such stringent goals being set does this context create a strategic situation for Terasen whereby in the long run any business based on fossil fuels will have to undergo dramatic changes?

Response:

Agreed.

To achieve these target reductions, consumption of fossil fuel energy at all levels within the economy will have to undergo change. This includes the direct use of natural gas in applications such as space and water heating. TGI has advanced proposals in this Application to attempt to meet the challenge.

24.2. Are the planning steps which need to be taken now to avoid stranded investments in the future apart from the steps Terasen is proposing of getting on board for the efficiency and conservation and the alternative energy solutions?

Response:

With this RRA, TGI has put forth proposals to help mitigate stranded investments that may occur in the future. These proposals include:

- Increasing the deprecation rate to better match the useful life of the TGI assets.
- Increasing the sales and marketing efforts and expanding energy efficiency initiatives to keep natural gas a part of the energy mix in BC on a go forward basis,.

- Integrating natural gas with alternative energy forms and solutions to meet customer needs and expectations.
- Expanding the mix of services to include alternative energy investments thereby broadening the base across which fixed costs are spread

These proposals do not guarantee that TGI will not have stranded assets in the future based on the changing conditions in which TGI operates within, but are key positive and proactive steps to mitigating the impacts of change on our customers and the Company.

25. Reference: Exhibit B-1, Page 51, Part III Section A Tab 1 – Customer Needs

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.

25.1. Does Terasen believe that customer information with regard to accurate and timely information will cause Terasen to need to get into upgrading all of its meters?

Response:

TGI customers have stated their preference for billing based on actual reads and their interest in more accurate and timely information related to energy consumption. TGI intends to pursue the most appropriate option for meeting these customer needs as they evolve further in the future.

25.2. What kind of information about home energy use is Terasen contemplating as a need?

Response:

Residential customers are interested in understanding their home energy use to both reduce their monthly bill and understand their impact on the environment. TGI anticipates more frequent information regarding home consumption based on actual meter readings will be required by residential customers and that customers will look to TGI to understand the impact of changes in their consumption. TGI also anticipates that residential customers will be interested in evaluating how quickly energy savings will pay for the cost of installing new equipment, conducting online home energy audits and understanding the impact of their home energy use on their overall carbon footprint.

25.3. Is it possible that mediating energy efficiency and conservation through individuals as a conscious activity will not be the optimal solution in the long term and is Terasen looking at more efficient ways to deal with customer decision making about GHGs, energy use planning and end use consumption efficiency and conservation?

Response:

TGI foresees that engaging customers directly in conservation and efficiency programs will continue to be an important and cost-effective activity for the utility, as defined by the Company's EEC Portfolio having an aggregate TRC of 1.0 or greater. As noted in the response to BCUC IR 2.26.1 on the Terasen Utilities' Energy Efficiency and Conservation Application[3]:

"The Companies believe that their strong and unique relationship with customers…provides the greatest value proposition to customers to having the utility continue to deliver DSM programs and offerings directly to the customer. The Companies have the primary relationship with natural gas customers, even those customers that have chosen to go with a gas marketer for commodity supply. The Companies maintain regular communication with customers through the following channels:

- *Monthly bills*
- *Bill inserts*
- *Customer newsletters*
- *www.terasengas.com*
- *Interactions with account managers*
- *Customer surveys*
- *Customer events*
- *Mass media communications*

…Research has indicated that the customers feel it is more appropriate for their utility to provide them with energy efficiency information and deliver energy efficiency programs than any other entity…"

In addition to TGI's direct EEC activity with customers, another channel through which the Company can "mediate energy efficiency and conservation" is the large-scale Integrated Energy Solutions described on pages 261 to 271 in Section 3.e of this Application. In providing geo-exchange and district energy systems, TGI would further facilitate efficiency and conservation for customers.

[3] Terasen Utilities' Response to BCUC IR No 2 on the Energy Efficiency and Conservation Application, August 15 2008, pp 53 to 54

26. Reference: Exhibit B-1, Page 57, Part III Section A Tab 1 – Competitive Position

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.

26.1. BC Hydro's Electricity prices now reflect on an ongoing basis the costs of conservation and efficiency to avoid higher marginal costs of new supply. In fact BC Hydro's most recent LTAP showed that 78% of future demand was going to be met from conservation and efficiency all of which is driving up BC Hydro's electricity rates. Further BC Hydro has sufficient additional conservation and efficiency waiting to be confirmed as cost-effective to move the market price for electricity to the market price of the marginal cost of conservation and efficiency. Does Terasen recognize that BC Hydro's electricity costs are increasingly subject to the similar market pressures as Terasen's are?

Response:

The Terasen Utilities acknowledge that the provincial policy change of reflecting price signals based on marginal costs in electricity rates represents movement in the right direction. The establishment of the RIB rate structure for the residential customers and the future establishment of similar rate structures in other customer classes may help the competitive position of gas versus electricity at some time in the future. However, the fact remains that the current and future BC Hydro RIB rates may take some time before the RIB Step 2 Rate reflects the true marginal cost of new supply. Until the RIB Step 2 rates better reflect the cost of new supply the Terasen Utilities business risks have not been reduced.

Further, for many customers the space and water heating energy requirements for a dwelling do not all come from consumption above the RIB Step 2 volume threshold. The RIB Step 1 rate is very low since it is calculated residually and is largely reflective of the fact that a large majority of BC Hydro's cost structure is based on low cost power from Heritage resources. The Terasen Utilities will continue to face competitive challenges based on the fact that the RIB Step 1 rate is as much or more the relevant comparator in many situations than the RIB Step 2 rate is.

27. Reference: Exhibit B-1, Page 68, Part III Section A Tab1 – Alternative Energy Solutions

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. 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. 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.

27.1. Does this $9.47/GJ levelized cost equivalent include all the capital costs for solar thermal?

Response:

Yes, the levelized cost presented in the solar-thermal example includes all estimated capital and operating costs for the solar-thermal system.

27.2. Does this$9.47/GJ levelized cost equivalent include the higher cost of providing the backup reliability, base supply and peaking capability required to provide equivalent service?

Response:

No. The solar energy system would be complimentary or supplementary to a conventional or other alternative "primary" energy system. As such, it would not require an additional back-up or peaking system. As a supplementary system, the $9.47 per GJ levelized cost of service would replace a portion of the variable costs of the primary energy system. For example, if this same 40-unit development was a Rate 2 TGI customer in the Lower Mainland today, they would currently pay $9.24 per GJ for the variable portion of their gas bill (midstream, delivery and commodity). For every GJ of natural gas they avoid at $9.24 by using solar thermal energy instead, that customer would pay the all-in solar thermal energy cost of $9.47.

27.3. What would the levelized cost equivalent be for a hydronic based system with solar thermal and natural gas base & backup peaking capacity?

Response:

The following response builds on the example provided in response to CEC IR 1.27.2. If it is assumed that the energy system serving the hot water needs of the development used as an example in Appendix C-27 is a combined solar-thermal and conventional natural gas system then a simple weighted ratio can be used to answer this question. The example identifies that approximately 30% of the energy requirements of the hot water system are supplied by the solar thermal system, which supplies 493 GJ per year. Therefore 70%, or 1150 GJ per year, is supplied by conventional natural gas. Working with the variable natural gas costs, the costs of the total system would be:

$$\frac{(1150\ GJ \times \$9.24ng) + (493\ GJ \times \$9.47st)}{1643\ GJ} = \$9.31 \text{ per GJ of energy}$$ [4]

The variable cost of $9.24 shown for natural gas does not include the natural gas hot water equipment or the basic monthly fee for natural gas service, since a wide range of equipment assumptions are possible and because the equipment would be required regardless of the installation of a solar-thermal energy system. The equipment costs for the solar-thermal system, however, are included in the levelized cost of service of $9.47 as described in Exhibit B-1, Appendix C-27.

[4] ng refers to natural gas while st refers to solar-thermal

28. Reference: Exhibit B-1, Page 71, Part III Section A Tab 1 – Economic Conditions

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

28.1. Given that these forecasts come from government budgets which were presented some time ago and that the forecasts on which they were based were based on assumptions made again sometime before that and given that virtually all governments since putting their budgets forward have had to acknowledge that their forecasts were overly optimistic does it make sense for Terasen to further update its forecasts?

Response:

Although TGI would agree that more recently published economic forecasts contain figures that, in some cases, are significantly different from those published during the first quarter of 2009 (and from which TGI's demand forecast was based), it does not necessarily follow that TGI should further update its demand forecast at this time. Housing starts, for example, were previously (Q1 2009 - CMHC) estimated to decline 34% in 2009 (from 2008 levels) and then estimated to decline a further 9% in 2010. The more recent forecast of housing starts (Q2 2009 – CMHC) is for an estimated 43% decline in 2009 (from 2008 levels) but then is estimated to increase by 10% in 2010. This implies housing starts in 2010 are now estimated to be approximately 37.3% lower than 2008 levels, whereas the first quarter 2009 forecast would estimate 2010 housing starts to be 39.9% lower than 2008 levels. The difference between these two forecasts for 2010, given that all customer additions represent only 0.6% of the total annual demand for natural gas (as discussed in TGI's response to BCUC IR 1.48.4), does not represent a material change in the overall demand forecast. And although this is only one

component of the demand forecast, TGI is currently in the process of re-evaluating its use per customer forecast and also the forecast of industrial demand to determine whether or not each of those components indicate there is a need to update the overall demand forecast.

29. Reference: Exhibit B-1, Page 72, Part II Section A Tab 1 – Economic Conditions

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.

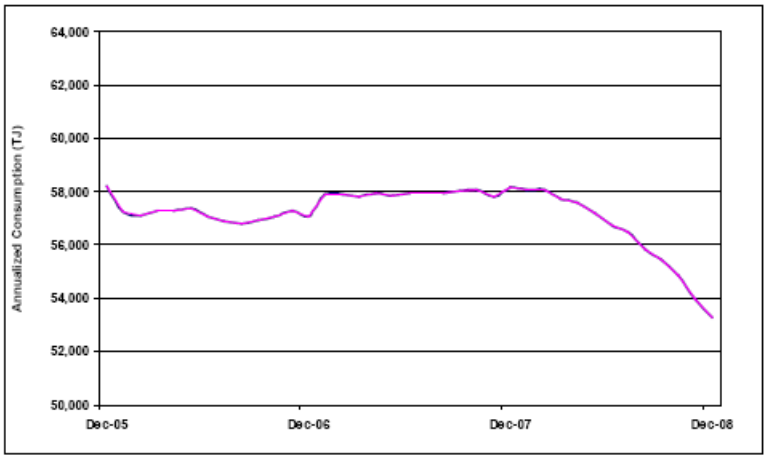
29.1. Does Terasen have a projected reduction in its energy consumption related to economic conditions, if so please provide this?

Response:

Please see TGI's response to BCUC IR 1.44.1

30. Reference: Exhibit B-1, Page 310, Part III Section C Tab 4 – Economic Conditions & Forecast Demand

Figure C-4-30: All Industrial Customers – Downward trend since early 2008



30.1. How has the customer demand in the industrial sector been tracking with respect to Terasen's forecast projection for 2009?

Response:

Please see TGI's response to CEC IR 1.31.1

30.2. Have the continuing problems for pulp and paper and for the wood products sector impacted customer demand more than Terasen had anticipated?

Response:

The challenging times being experienced by the Pulp & Paper and Wood Products sector, although more recent for the Pulp & Paper sector, have been ongoing over recent years and are part of the cyclical nature of the economy. And given that TGI, on an annual basis, surveys its industrial customers and uses the results to form the basis for the industrial demand forecast, the continued challenges faced by these two sectors have in large been anticipated.

31. Reference: Exhibit B-1, Page 311, Part III Section C Tab 4 – Economic Conditions & Forecast Demand

Table C-4-8: Forecast Energy Consumption (PJs)[171]

	Projected 2009	Forecast 2010	Forecast 2011
Residential[1]	71.0	67.8	67.2
Commercial[2]	47.5	47.3	47.9
Firm Sales[3]	3.4	3.4	3.3
Industrial[4]	45.2	43.4	43.3
Total	167.3	162.0	161.8

Notes
1. Rate 1
2. Rates 2, 3 & 23
3. Rates 4, 5 & 6
4. Rates 7, 22, 25 & 27 (does not include Burrard Thermal & TGVI)

Note: 2009 projections include three months of actuals (not weather normalized)

31.1. Has Terasen's actual experience for 2009 been as forecast or has it been lower than forecast?

Response:

The following table illustrates the projected and actual demand for residential, commercial, firm sales, and industrial customers over the period January through June 2009.

	YTD 2009 Projected	YTD 2009 Actual	Variance (Act. to Proj.)
Residential[1]	41,648.50	43,161.57	3.6%
Commercial[2]	28,408.50	28,986.7	2.0%
Firm[3]	1844.3	1,786.0	-3.2%
Industrial[4]	24,171.3	25,096.8	3.8%
Total	**96,072.60**	**99,031.04**	**3.1%**

Note:
1. Rate 1 customer class
2. Rates 2, 3 & 23 customer classes
3. Rates 4,5,6 customer classes
4. Rates 7,22,25, & 27 customer classes

As can be seen, actual demand for residential, commercial and industrial customers has been slightly above projected levels, but for firm sales customers has been below projected levels. Given that for Residential and Commercial customers, the above projections contain actual results for the first quarter of 2009 and then projections based on the expectation of normal

weather for the second quarter of 2009, a more appropriate comparison of actual to projected demand is illustrated in the following question, CEC IR 1.31.2, where normalized results are illustrated over the entire period.

31.2. What effect would having weather normalized values in 2009 have?

Response:

The following table illustrates the projected and actual demand for Residential, Commercial, Firm Sales, and Industrial customers over the period January through June 2009. Residential and Commercial volumes are weather normalized, whereas Firm Sales and Industrial demand is actual results.

	YTD 2009 Projected	YTD 2009 Actual Normalized	Variance (Act. to Proj.)
Residential[1]	39,232.83	38,087.74	-2.9%
Commercial[2]	26,347.12	25,947.2	-1.5%
Firm Sales[3]	1844.3	1,786.0	-3.2%
Industrial[4]	24,171.3	25,096.8	3.8%
Total	**91,595.55**	**90,917.71**	**-0.7%**

Note:

1. Rate 1 customer class
2. Rates 2, 3 & 23 customer classes
3. Rates 4,5,6 customer classes
4. Rates 7,22,25, & 27 customer classes

As can be seen, actual demand for Residential, Commercial, and Firm Sales customers for the first six months of 2009 are below projected levels, while industrial demand has been above projected levels. Overall, actual demand over this period has been 0.7% below projected levels.

32. Reference: Exhibit B-1, Page 76, Part III Section A Tab 1 – Demographic Challenges

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.

32.1. Terasen deals with demographic challenges as an employee workforce issue. Does Terasen see any of the demographic issues creating fundamental customer and marketing issues for the company?

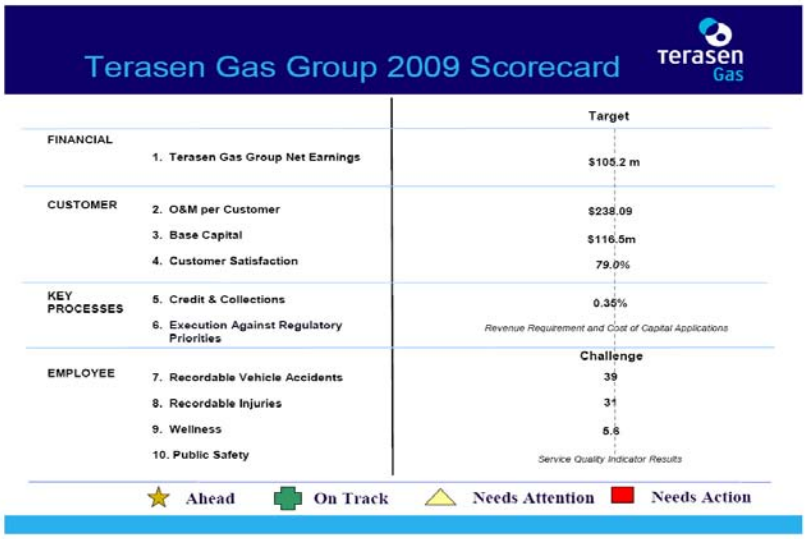
Response:

The Company expects that changes in service delivery and all interaction with our customers (including any marketing efforts) will change for several reasons, including employee and stakeholder demographics. TGI regularly surveys customer satisfaction with our service levels (surveys, focus groups, complaint monitoring, etc.), and through this process and the associated data analysis, trends are revealed that allow TGI to make proactive changes in our service offerings to meet changing customer requirements. These changing needs are a fundamental consideration requiring some flexibility and agility in TGI's long term investments and programs to allow for evolution in customer wants and needs.

TGI will need to address changes in customer requirements by adjusting our corporate skill sets and capabilities in response. This can be accomplished by training current employees and/or hiring new skill sets. We do not anticipate demographic challenges within the Sales & Marketing groups to be any more challenging than those affecting the rest of the Company.

33. Reference: Exhibit B-1, Page 100, Part III Section B Tab 1 – Utility Management

Figure B-1-2: Balanced Scorecard Used in 2009



33.1. Given Terasen's new directions with respect to Energy Conservation and Efficiency, and Alternative Energy Solutions has Terasen given consideration as to whether or not its scorecard need to have an Environmental & Social Responsibility section?

Response:

Although there is no explicit measure on the Scorecard for measuring it, the importance of environmental and social responsibility underpins Terasen Gas' ongoing commitment to Operational Excellence today. We conduct our business in a safe and environmentally responsible manner to ensure our activities have no lasting ill effects on the environment. We are socially responsible by providing support through programs and sponsorships to the communities in which we operate in.

Terasen Gas recognizes that its business and priorities continues to evolve and is regularly reviewing its scorecard measures to ensure they are the right ones. As environmental and social responsibility is inherent in what Terasen Gas does, it is not necessary to add an Environment and Social Responsibility section to the scorecard at this time.

The use of the balanced scorecard brings balance and transparency to Terasen Gas business; provides focus to deliver on a series of key success measures critical to its business; aligns its business activities and maintain its focus on Operational Excellence for the benefit of customers and shareholders.

34. Reference: Exhibit B-1, Page 106, Part III Section B Tab 1 – Economic Conditions & Customer Demand

Net customer additions have averaged 9,800 per year over the period 2003 through 2008. Net customer additions have grown from a low of 5,546 in 2003 to a high of 12,474 in 2005, but have since been declining. The decline in net customer additions relative to gross customer additions is attributed to the slowdown in the housing market, and also increased customer attrition, which is discussed in Part III, Section C, Tab 4.

34.1. Please provide the customer attrition counts for the years 2000 to 2008.

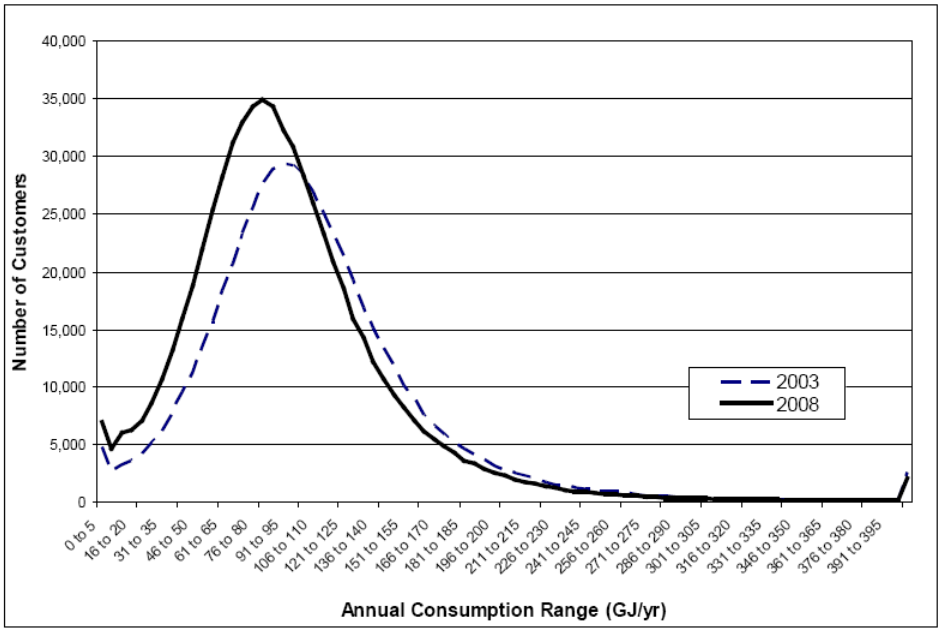
Response:

The following table illustrates the Gross and Net Customer Additions, ratio of Net to Gross Customer Additions, and also the Customer Attrition counts over the period 2000 to 2008.

	2000	2001	2002	2003	2004	2005	2006	2007	2008
Gross Additions	7,400	5,300	8,300	12,837	15,549	12,770	13,338	15,533	14,566
Net Additions	6,544	4,865	6,606	5,546	11,504	12,420	10,181	9,915	9,247
Ratio of Net to Gross Additions	88%	92%	80%	43%	74%	97%	76%	64%	63%
Customer Attrition	**856**	**435**	**1,694**	**7,291**	**4,045**	**350**	**3,157**	**5,618**	**5,319**

35. Reference: Exhibit B-1, Page 107, Part III Section B Tab 1 – Economic Conditions & Customer Demand

Figure B-1-4: Residential Consumption is Declining



35.1. The data in the above graph appear to overwhelmingly support a view that the most prominent change over the time period has been to new customers with lower load requirements. The slippage of existing customers to lower average consumption appears to be slim or at least is being largely replaced. This interpretation of the data would seem to correspond well with the shift to multi-family dwellings and their smaller average sizes and lower natural gas consumption profiles. Does Terasen agree with this interpretation or is Terasen's view more in line with the title of the graph that residential consumption is declining.

Response:

The above graph does illustrate the fact that average use per customer is declining. TGI would agree that the data could support a view that the most prominent change has been to new customers with lower load requirements, which corresponds well with the shift towards more multi-family dwellings in the housing mix. However, the absence of customer specific data such as initial attachment date and housing type (which became available in 2006) leaves TGI unable to confirm for certain that this is the case.

36. Reference: Exhibit B-1, Page 110, Part III Section B Tab 1 – Economic Conditions & Customer Demand

Table B-1-3: Historic Total Demand has been declining over the PBR Period

	Normal 2003	Normal 2004	Normal 2005	Normal 2006	Normal 2007	Normal 2008	Projected 2009
Residential[1]	72.6	72.0	69.3	70.0	70.6	68.8	71.0
Commercial[2]	45.3	45.2	43.9	44.1	45.5	45.9	47.5
Firm Sales[3]	6.1	5.3	4.7	4.1	3.8	3.5	3.4
Industrial[4]	60.1	58.3	58.6	54.2	56.3	51.8	45.2
Total	**184.1**	**180.8**	**176.5**	**172.4**	**176.2**	**170.0**	**167.3**

Notes
1. Rate 1
2. Rates 2, 3 & 23
3. Rates 4, 5 & 6
4. Rates 7, 22, 25 & 27 (does not include Burrard Thermal & TGVI)

36.1. Presumably this table is reflecting demand in PJs. Is the data weather normalized? The most notable decline of demand is for the industrial sector. Does Terasen have any analysis as to how much of this decline is related to weakness in BC's economy, which may rebound at some point and how much is related to structural changes in the industrial sector which will result in demand disappearing such that it will not return? Firm sales are also declining significantly. Does Terasen have an analysis as to what is causing this decline?

Response:

TGI confirms the above table is reflecting demand in PJs, the residential and commercial data is weather normalized, and the firm sales and industrial data is non-weather normalized. Although TGI attributes a significant portion (if not all) of the declines seen in the industrial sector to the weakness in B.C.'s economy, as discussed in TGI's response to BCUC IR 1.44.1, given the uncertainty regarding the duration of the economic downturn and also how the downturn will ultimately impact the structure of the B.C. economy, TGI does not have an analysis which distinguishes between demand that has temporarily declined versus demand that has permanently declined, but may see some indication of this from the industrial survey results, which are in the process of being evaluated. The primary reason for the declining trend in firm sales volume is customer migration out of the Rate 5 customer class to transportation service rate schedules, although more recent declines are likely due to the economic downturn.

37. Reference: Exhibit B-1, Page 111, Part III Section B Tab 1 – Economic Conditions & Customer Demand

Over the PBR Period the Company has seen a decline in total energy demand. As can be seen in Figure B-1-7 above, this has been primarily driven by declines in the firm sales and industrial and transportation customer segments. And given current economic conditions, it is likely that these trends will continue. The residential and commercial segments, although proving more stable in terms of total energy demand over the PBR Period, are highly influenced by more recently emphasized energy efficiency efforts and also a continuing shift in the housing mix. With these trends expected to continue, it is reasonable to conclude that total energy demand will continue to decline.

37.1. Would Terasen's conclusions change significantly if Terasen were able to capture a much higher percentage of the multi-family dwelling market?

Response:

TGI's conclusions would not change significantly if capture rates for multi-family dwellings were much higher than they presently are. Given that customer additions, over the forecast period, are expected to represent approximately 0.6% of total demand, even a 50% increase in customer additions (assuming the current mix of single and multi-family dwellings) would only increase the portion of total demand customer additions represent to 0.9%. Therefore, capturing a much higher percentage of the multi-family dwelling would increase the overall demand for natural gas, but would not necessarily reverse the downward trends currently being experienced.

38. Reference: Exhibit B-1, Page 116, Part III Section B Tab 1 – Marketing & Revenue

success. To address the rapidly changing energy use in modern homes, Terasen Gas is proposing to expand its analysis of how customers use natural gas. This type of analysis helps the utility improve its forecasting accuracy and assists in bringing marketing offers to customers that they find valuable. Other studies range from small focus groups to broad, web or phone-based research surveys designed to help Terasen Gas design and deliver new services and products that customers want from their natural gas provider.

38.1. Will Terasen be focused on adding these new services and products as market offers which are unbundled and are supported by their own revenue stream or will Terasen be rolling them all into the existing services and potentially increasing prices to support the new activities?

Response:

At this point in time it is too early to theorize what form the new service offerings will take as we have yet to begin to "expand its analysis". If TGI is successful in this Application with respect to the revenue requirement for these initiatives, it will undertake the analysis. At the time TGI has the results of the analysis, it will then determine what form these new market offers should take and how the new market offers should be supported. If required, TGI would make an application to the Commission seeking approval for the new offering at that time.

39. Reference: Exhibit B-1, Page 121, Part III Section B Tab 1 – Marketing & Revenue

Terasen Gas believes that these changes resulted in more appropriate price signals to customers reducing the disincentives to attaching to the Terasen Gas system. Terasen Gas expects to achieve incremental customer connection activities as a result of the System Extension and Connection Policy Application approval in the years to come.

39.1. Has Terasen seen any identifiable benefits from the these System Extention & Connection Policy changes to date?

Response:

Yes, the Company has seen identifiable benefits from the System Extension and Customer Connection policy changes which were approved by the Commission and implemented on January 1, 2008. As presented in the 2008 Year End TGI and TGVI Main Extension Report (refer to Appendix E-2 of the Application), under the new policy the Company has extended the natural gas system and attached a greater number of new customers without harming existing customers.

The new policy requires the individual main extension Profitability Index ("PI") to be 0.8 or greater, and also requires the aggregate PI to be 1.1 or greater, whereas the old policy required only the individual main extension PI to be 1.0 or greater. In the 2008 Year End TGI and TGVI Main Extension Report, TGI reported that for completed 2008 main extensions the average actual PI was 1.2, above the threshold of 1.1. Approximately 10% of those main extensions (27 of them) had a PI between 0.8 and 1.0. Therefore, TGI can state that approximately 10% of the main extensions completed in 2008 were approved as a result of the changes to the System Extension & Connection Policies to date.

40. Reference: Exhibit B-1 Page 137, Part III Section B Tab 1 – Operational Performance

- Once the software has been in service for a complete year, the following benefits will be fully realized:
    - Improved optimization of field resources;
    - Elimination of complex, duplicated, and error prone resource management processes;
    - Elimination of manual data validation and entry;
    - Elimination of time and costing data reconciliation;
    - Improved communication between Dispatch and field employees;
    - Automation of preventative maintenance processes; and
    - Access to historical maintenance data in the field.

40.1. This project appears like it will be contributing significantly to improved efficiency in the future. Has Terasen estimated what these benefits will contribute and if so what is the $ value?

Response:

Yes, this project is envisioned to contribute significantly to improved efficiency in the future. As outlined in the CPCN Application dated May 7, 2007, the project's operational benefits were outlined as follows:

Area of Benefit	Department	Annual Saving
Elimination of Manual Data Validation and Entry.	Distribution	$58,000
Elimination of Time and Costing Data Reconciliation.	Human Resources	$57,500
Improved Optimization of Field Resources.	Distribution	$350,000
Improved Communication between Dispatch and the Field.	Distribution	$27,500
Elimination of Complex, Duplicated, and Error Prone Resource Management Processes.	Distribution	$41,000
Field Resources Using a Single System.	Distribution	$42,000
Total		**$576,000**

All of the above noted financial benefits are incorporated in the Application for 2010 and 2011 O&M budgets. Further efficiencies in the area of improved optimization of field resources were budgeted at $724,000 and $588,000 for 2010 and 2011, respectively (compared to 2009 as a base). Investment in IT systems during the PBR Period is contributing to efficiencies now and into the future.

41. Reference: Exhibit B-1, Page 147, Part III Section B Tab 1 – PBR & FTE

Table B-1-7: No Increase in FTE Employees Between 2003-2008

Terasen Gas
FTE Reconciliation

	2003	2004	2005	2006	2007	2008
Distribution	510	499	488	468	481	503
Finance, Reg Affairs	58	59	61	59	58	63
President	43	4	2	2	2	2
Business & IT Services	311	284	298	293	300	311
HR & Operations Governance	92	93	90	85	84	87
Marketing	86	65	64	75	80	80
Gas Supply & Transmission	89	85	89	80	81	80
Total TGI	**1,189**	**1,089**	**1,092**	**1,062**	**1,087**	**1,127**

41.1. Terasen appears to have delivered a reduction of about 100 staff early in the PBR period and as of 2008 and presumably 2009 appears to have reacquired a good portion of the staffing.

41.1.1. Was Terasen rewarded for the staff savings or some portion of them under PBR and if so how much?

Response:

Where reductions in number of employees translated into lower O&M, the achieved savings were shared equally between customers and the Company, according to the PBR Agreement.

Comparing the formula labour costs based on the 2003 Decision to the resource view total labour costs shows the following savings resulting strictly from labour. This estimate does not account for any non-labour or benefit savings that would be associated with changes in headcount. This table shows an estimated $19 million in pre-tax savings for customers, and $19 million in pre-tax savings for the Company over the PBR Period.

	Amounts in $ thousands							
	2003	2004	2005	2006	2007	2008	2009	Total
Formula Labour	80,185	81,645	83,770	85,888	88,201	89,945	91,176	600,810
M&E Costs	36,478	32,751	30,927	36,995	41,161	38,581	43,087	259,980
COPE Costs	22,378	22,557	23,109	22,382	21,966	23,046	24,792	160,230
IBEW Costs	20,125	19,824	20,399	18,559	19,926	21,201	22,301	142,335
Total Actual Labour	78,981	75,132	74,435	77,936	83,053	82,828	90,180	562,545
Labour Savings	1,204	6,513	9,335	7,952	5,148	7,117	996	38,265
Sharing at 50%	602	3,256	4,667	3,976	2,574	3,559	498	19,133

41.1.2. Does this data demonstrate that a significant portion of the savings achieved under PBR has not been and is not sustainable?

Response:

In the absence of any additional information, this data on its own does not demonstrate whether savings are sustainable. What is clear is that significant savings were achieved as compared to the formula based labour costs during the PBR Period, which were shared equally by customers and the Company.

The reductions in specific positions that were undertaken early in the PBR period are generally sustainable in a static environment. However, over time, changes in external requirements (for example increases in the number of customers, changes in customer expectations, codes and regulations, and energy policy) result in increasing staffing requirements to meet those expectations. Although the total headcount may increase as a result of these changes, the composition of the workforce will be significantly different than at the outset of the PBR Period.

As demonstrated in the tables and discussion on pages 346 and 347 of the Application, TGI has been able to retain a significant portion of the savings achieved, even though the opportunity for achieving incremental large scale efficiencies has been largely exhausted.

42. Reference: Exhibit B-1, Page 158, Part III Section B Tab 1 – PRB & EMS

Table B-1-10: Customers Realized $69 million in Savings as a result of the ESM

	Actual					Projection	
	2004	2005	2006	2007	2008	2009	Total
O&M Savings	$ 5.9	19.1	16.9	19.7	13.6	8.0	$ 83.2
Depreciation Savings	1.7	3.5	3.4	9.5	9.2	10.0	37.3
Rate Base (Earned Return)	(0.6)	(1.1)	5.7	4.3	2.9	5.7	16.9
Gross Margin	(2.0)	0.6	(1.9)	(2.5)	0.3	1.5	(4.1)
Other Revenue	(2.5)	(2.7)	(2.1)	(2.9)	(1.9)	(2.5)	(14.6)
2009 tax adj - overhead/CCA rates; SCP landscaping	-	-	-	-	-	12.6	12.6
Tax timing differences (mainly CCA)	1.2	1.6	(0.6)	1.8	1.2	0.9	6.1
Pre Tax Earnings Available for Sharing	$ 3.6	$ 21.0	$ 21.3	$ 29.9	$ 25.5	$ 36.1	$ 137.4
Customers' 50% Share of Earnings (pre-tax)	**$ 1.8**	**$ 10.5**	**$ 10.7**	**$ 15.0**	**$ 12.7**	**$ 18.0**	**$ 68.7**

Numbers shown are in $ millions

42.1. How does Terasen assure customers that the savings on capital projects are real?

Response:

The savings on capital projects as detailed in Table B-1-10 result from both rate base reductions and depreciation. To develop the numbers included in this table, the actual amounts of rate base and depreciation expense are compared to the formula-driven amounts that were used to set rates, and any differences are shared equally between customers and the Company. Therefore, the amounts shown in the table are real in the sense that those savings have been included in the determination of customers' rates at each year's Annual Review, and also in the determination of the Company's net income. An alternative method to measure capital savings would be to compare the actual capital expenditures against the budget for each of those years. This analysis has been completed and is included in response to BCOAPO IR 1.38.1.

42.2. How can customers be sure that capital projects or capital expenditures are not just deferred to a later period or achieved as a consequence of the capital expenditure mix?

Response:

Please refer to the response to BCOAPO IR 1.5.2.

42.3. Is the ESM the most efficient and cost effective way to actually capture these savings to the extent they are real?

Response:

The ESM is one method for capturing the savings between the allowed ROE used in rate setting and the actual achieved ROE, and return those savings to both the customers and the Company. There are other methods that are available, and many different methods are in place in different utilities throughout Canada. The ESM is the method that was agreed to as part of the PBR Agreement.

As indicated in the response to CEC IR 1.42.1, the amounts shown in the earnings sharing table are real. The savings that have been realized have been passed on to customers through the earnings sharing mechanism, and included in the determination of customers' rates, and are also reflected in Terasen Gas' net income.

43. Reference: Exhibit B-1, Page 161, Part III Section B Tab 1, - PBR & EMS

- The implementation of large scale Information Technology solutions;
- Internal departmental reorganizations and streamlining;
- Deferring activities and related costs where safe and prudent to do so, particularly where the activities were of a cyclical nature;
- A strong focus on achieving a lower bad debt experience rate;
- Leaving vacancies unfilled, both planned and unplanned due to difficulties in attracting and retaining specific jobs in a strong economic cycle; and
- The utilization of new technology that allowed for reduced manpower.

43.1. When capital expenditure investments are made in cost saving projects Terasen will earn its ROE on its Equity investment and Lenders will earn their interest rate on their investment. Can Terasen demonstrate that providing 50% of the benefits of a project back to the equity investor for a period of time represents the most cost effective way to enhance and capture benefits from capital investments?

Response:

The capital efficiency mechanism included in the PBR Agreement provided an incentive to TGI to reduce capital spending not to increase it. The base capital spending included in rate base during the PBR term was derived from formulas using annual customer additions and the overall customer count as drivers. Rebasing for actual capital spending did not occur during the PBR term. By making a capital expenditure on cost saving projects TGI would have been using up the room in its formula-based capital spending allowance and therefore losing the potential capital efficiency incentive on that spending. Since the PBR Agreement incented TGI to achieve both O&M and capital efficiencies it was necessary to balance the gain from O&M efficiencies against the loss in the capital efficiency mechanism for the type of capital investment described in the question. TGI believes that the PBR Agreement mimicked, in a sense, the trade-off that companies in a competitive market would make in deciding to spend capital to generate operating cost savings.

This capital / O&M trade-off is what was implicit in the approved PBR Agreement. TGI believes that the PBR Agreement as a total package, including the capital incentive, was very effective in creating value for customers and the Company. TGI cannot confirm, however, that the capital incentive portion of the PBR Agreement, taken on its own, was the most cost effective way to enhance and capture benefits from capital investments.

44. Reference: Exhibit B-1, Page 188, Part III Section B Tab 1 – Operational Performance

Prior to 2006, Terasen Gas managed the residential meter fleet to a 28 year life span enabled by one maintenance and recondition operation at the midpoint of this 28 year life. This resulted in a meter recall frequency of 14 years. Communications with vendors, ongoing discussions within the Canadian Gas Association Measurement Committee and the company's own internal analysis, provided Terasen Gas the confidence to target a 20 year life span for the residential meter fleet without a mid-life recondition operation. This allowed Terasen Gas to temporarily reduce the number of meter recalls over the period 2006 - 2008 to bring the demographics of the meter fleet in line with a 20 year life expectancy which provided both customers and shareholders the cost benefits of previous investment in the fleet.

44.1. Did Terasen prepare a business case to demonstrate the cost effectiveness of this approach to shortening the life of the meter fleet in service and if so please provide the study?

Response:

TGI has assessed the cost-effectiveness of the approach, but it is not formally documented in a study. The analysis undertaken, which demonstrates that the approach is the preferable one, is summarized below.

Terasen Gas' strategy related to the refurbishment of meters has been largely influenced by the relative difference between the labour expense associated with meter refurbishment and the purchase price of new meters. In the case of commercial and industrial meters which incur a relatively high replacement cost, the decision to refurbish the meters has proven to be the more cost effective option. As such, Terasen Gas currently engages in the practice of recalling these meters for refurbishment and re-deployment into the field. Alternatively, residential meters are manufactured in relatively large quantities allowing vendors to benefit from the resulting economies of scale. As a result, the unit price for residential meters has remained relatively low in relation to labour costs associated with meter refurbishment. Therefore, the decision to operate the residential meters to the end of their useful lives prior to replacement is currently the most cost effective approach to meter management.

The expenses involved in this analysis are monitored by Terasen Gas as part of normal operation and therefore the analysis has not been documented within a formal study.

44.2. What sort of data was used in making the determination that a 20 year life would be feasible and if any please provide the analysis?

Response:

Terasen Gas regularly engages in technical discussions with vendors regarding meter life expectancy. In particular, Terasen Gas makes enquiries regarding adjustments vendors have made to their manufacturing processes and the resulting impact these adjustments may have on meter performance. Information gathered through these discussions is reconciled with the results of TGI's annual performance sampling program in order to determine the life expectancy for each meter group by year. As such, ongoing review of the historical results from this performance monitoring program has given Terasen Gas the confidence to adjust the meter recall schedule to reflect a 20 year life expectancy for residential meters. Furthermore, Terasen Gas has validated this decision through various discussions with technical employees from other gas utilities represented on the Canadian Gas Association measurement committee. Going forward, TGI will continue to closely monitor the performance of the meter fleet through the performance sampling program while acting upon the proactive measures to align the vendors with the Company's meter performance targets as described in BCUC IR 1.170.1.

44.3. Is a meter exchange and reconditioning feasible after 20 years and if not why not?

Response:

As described within CEC IR 1.44.1, the refurbishment of higher cost commercial and industrial meters is a feasible strategy that continues to be followed by Terasen Gas. Alternatively, the relatively low purchase price of residential meters makes replacement of these meters a more cost effective option in comparison to refurbishment. As such, residential meters are scheduled for replacement in the period which the measured life expectancy is reached.

45. Reference: Exhibit B-1, Page 221, Part III Section C Tab 2 – PBR & ESM

timing differences. The total of all these impacts is a decrease in the revenue requirement of $22.4 million resulting from moving from formula to forecast.

45.1. If the PRB and ESM were continuing would the $22.4 million have represented savings which would have been shared between TGI and its customers?

Response:

The $22.4 million is calculated based on the difference between 2009 formula and 2009 forecast. The sharing for the forecast period under a PBR and ESM extension scenario would be calculated based on the same components but using 2010 and 2011 amounts and therefore the resulting amount of sharing could be significantly different. In this RRA, as a result of rebasing, the savings, after being adjusted for the end-of-term capital incentive mechanism, will flow directly to customers through reduced rates instead of through earnings sharing.

46. Reference: Exhibit B-1, Page 224, Part III Section C Tab 2 – Delivery Rate

To support our Energy Efficiency and Conservation Program and to meet the evolving needs of our customers, we propose that the basic charge and administration fees be held at existing approved 2009 levels. As such, the proposed volumetric and demand based delivery rates have been adjusted to account for the revenue that would have been collected from the changes in the basic charge or administration fees in 2010 and 2011.

46.1. Please provide the revenues for 2010 and 2011 that would have been collected from changes in the basic charge and administration fees had the revenue requirement been set across the board and please provide the rate increase amounts and revenue requirements by rate class required to support not implementing delivery rate increases across the board?

Response:

The revenue that would have been collected from changes in the basic charge and administration fees is approximately $157.1 million in 2010, or $8.3 million more than proposed, and approximately $163.9 million in 2011 or $14.1 million more than the proposed.

The incremental revenue that would have been collected from changes in the basic charge and administration fees of $8.3 million in 2010 and $14.1 million in 2011 for each rate schedule, as proposed in the Application, is being collected through the volumetric and demand delivery rates for each rate schedule. For example, the revenue that would have been collected from the increase in the basic charge and the administration fees for the Residential customer group will now be recovered through the volumetric delivery charge for the Residential customer group. In other words the total forecast revenue to be received under the proposed rates would be equal to the amount that would have been collected had the rates been set across the board (including the basic charge and administration fees).

A change in the allocation to the various delivery rate components would not affect the proposed annual average bill impacts or the proposed total revenue collected from each Rate Schedule because the allocation of the revenue deficiency to each Rate Schedule would not be impacted by this change. The revenue deficiency allocated to each Rate Schedule would remain as presented in Schedules 22-25, column 8 in Section C, Tab 13.

47. Reference: Exhibit B-1, Page 225, Part III Section C Tab 2 – ESM

The ESM Rider reflects a 2009 projected earning sharing amount owing to customers of $18.0 million at December 31, 2009. As noted in the Rate Base discussion (Part III, Section C, Tab 8) we are proposing that this balance be returned to customers over a two-year period as opposed to the one year period as approved in Commission Order No. G-51-03, to align the ESM rider with the impact of the End-of-Term Capital Incentive Sharing Mechanism and to smooth out the rate impact associated with the expiration of the ESM rider.

47.1. Does this proposal mean that the customers would receive $9 million credit in each of 2010 and 2011?

Response:

Yes, TGI is proposing to credit customers with an estimated $9 million in earnings sharing for both 2010 and 2011. Schedule 70 in Section C Tab 13 of the Application provides a breakdown of the proposed components of the ESM Rider and the resulting rate rider (per gigajoule) for each rate schedule. The actual amount of earnings sharing available will not be known until the second quarter of 2010, and any differences between the estimated amount and the actual will be adjusted in rates in 2011.

47.2. Does Terasen compute interest benefit into the customer ESM account when it proposes to hold the amounts owing to customers over a two or multiple year period?

Response:

No, TGI has not computed an interest benefit into the ESM account. Since the ESM deferral account serves to reduce rate base, customers are held whole through reduced rates due to the inclusion of this credit balance in rate base. Interest treatment is normally afforded for either non-rate base accounts, or accounts where a significant variance from the amount included in rate base is common.

48. Reference: Exhibit B-1, Page 226, Part III Section C Tab 2 – RSAM

The RSAM Rider reflects a projected balance of $13.2 million owing to customers at December 31, 2009. As noted in Part III, Section C, Tab 8, RSAM account balances will continue to be recovered from or returned to customers through Delivery Rate Rider 5 over a three year period. This results in a credit rider of $0.053/GJ in 2010 which is reduced by of $0.001/GJ in 2011 for a total rider $0.052/GJ in 2011 applicable to Rate Schedules 1, 2, 3, and 23.

48.1. Does Terasen compute interest benefit into the customer RSAM when the proposal has the RSAM being credited back to customers over three years?

Response:

Please see the response to CEC IR 1.47.2. In the case of RSAM, since there can be a significant variation between the amount included in rate base forecast and the actual amount realized, interest is calculated on this variance and the projected amount only is included in rate base. See response to BCUC IR 1.158.1 for an analysis of how the interest amounts are calculated for the RSAM and similar accounts.

49. Reference: Exhibit B-1, Page 226, Part III Section C Tab 2 – Interim Rates

As indicated in Section D, since a Decision on this RRA may not be in time for permanent rates to be implemented on January 1, 2010, Terasen Gas requests approval for interim rates effective January 1, 2010. The interim rates would apply to all non-bypass customers whereby the margin increase in rates

49.1. What would be the latest point in the 2009 year that a decision could be rendered from the Commission on interim rate relief and still be implemented by January 1, 2009?

Response:

TGI would require approximately three weeks to prepare the tariff pages with the proposed January 1, 2010 interim rates and file these tariff pages with the Commission, and to provide Accenture Business Services for Utilities with the new rates effective January 1, 2010, to be entered into and tested in the TGI billing system.

50. Reference: Exhibit B-1, Page 228, Part III Section C Tab 3 – EEC

specific programs under Innovative Technologies. For TGI in 2010, these new programs add $2.8 million to the amount approved by BCUC Order No. G-36-09. An additional $6.5 million for 2011 is being sought for Interruptible Industrial programs and Innovative Technologies. This spending is outlined in the table below. The funding for EEC activities represents a placeholder for total dollar amounts that can be used to delivery programs to the benefit of customers. This funding envelope represents the total amount of dollars that would be spent by the Company on EEC activities for 2010 and 2011. However, over time, only the actual spend on EEC activities will be charged to the EEC deferral account and ultimately reflected in customers delivery rates.

50.1. Please identify the impact on 2010 and 2011 revenue requirements and rates for this increased EEC funding request assuming it is all actually spent and goes into the deferral account.

Response:

The impact on the revenue requirement of the increased EEC funding of $2.8 million in 2010 and $6.5 million in 2011 is approximately $0.1 million in 2010 and approximately $0.6 million in 2011, resulting in an approximate delivery rate increase of 0.02% in 2010 and an additional increase of 0.10% in 2011 (cumulative impact of 0.12% in 2011).

50.2. Is the conservation impact of these expenditures forecast and included as reductions in net revenues or is that left to unfold in future years as part of the variance from forecast?

Response:

The conservation impact of the EEC expenditures is included as reductions in net revenues, and therefore is not left to unfold in future years as part of the variance from forecast.

51. Reference: Exhibit B-1, Page 231, Part III Section C Tab 3 – EEC

report used to refine the results of the CPR. The evidence demonstrates the benefits of extending funding for a further year.

51.1. What benefits are these and who benefits?

Response:

The "benefits" in the excerpt from the Revenue Requirement Application referred to in the IR are the benefits from EEC activity as delineated in the Terasen Utilities' EEC proceeding and as accepted by the Commission in its Decision G-36-09. These are discussed at a high level in the response to BCUC IR 1.26.1 and in more detail on pages 90 to 100 of Section 7 of the Terasen Utilities' EEC Application. The continuation of already-approved 2010 EEC funding to 2011 as requested in this Revenue Requirement Application will ensure that EEC benefits continue to accrue to customers and to the Company.

52. Reference: Exhibit B-1, Page 231, Part III Section C Tab 3 – EEC

greenhouse sector. Since the time of the Manufacturing CPR, forestry has significantly declined with many operations either closed, idled and in a number of cases, in bankruptcy proceedings. Those that are operational may have difficulty raising capital for asset expenditures or have already taken steps to become efficient and that has partly led to their resilience. Similarly, nearly all greenhouses have

52.1. How is Terasen protecting itself and its customers against the possibility of investing in EEC in a company that severely curtails its business or goes out of business?

Response:

The excerpt referred to in the Information Request refers to the section of the Revenue Requirement that deals with Interruptible Industrial EEC. TGI has commissioned an update to its 2006 manufacturing CPR, as provided in Attachment 2.1 of the response to MEMPR IR 1.2.1. Its contents provide TGI with a snapshot of conservation potential within the manufacturing sector. The issue of protecting customers from exposure to undue risk from investing industrial EEC funds in an entity that either severely curtails its operations or goes out of business is one that the Company takes very seriously. TGI does not have experience with developing industrial EEC programs; managing risk associated with industrial EEC will be one of the key roles of the dedicated Industrial EEC resource that TGI has proposed in this Application.

52.2. What is Terasen's experience to date with funds spent to achieve savings, which have then subsequently been lost because of a curtailment of business activity or a complete shutdown?

Response:

TGI has not had any experience to date with the loss of EEC savings in industrial EEC because TGI has not historically had EEC programs designed for this sector. As noted in response to CEC IR 1.51.1, the new Industrial EEC staff person would be charged with developing processes and procedures to limit the risk to TGI of customers taking incentives and then ceasing to operate. These processes could take the form of special contracts with security provision or other such mechanisms.

In terms of TGI's historical EEC activity in the residential and commercial sectors, the investments made by the Company in individual participants have not been significant. The largest incentives that have historically been available have been through TGI's Efficient Boiler Program, and these averaged $19,379 per participant in 2008, with an associated 1373 GJ/year in annual savings. While not insignificant, the loss of 1373 GJ/year should a participant in the Efficient Boiler Program cease to provide those savings would not have had a major impact on overall Portfolio TRC. Now that TGI is moving into an arena with the EEC decision where both the incentives and the associated savings are going to be significantly larger than those in the past, the Company is acutely aware of the need to manage risk. Risk management approaches will need to vary from program to program, and will be a fundamental part of program design for programs where large financial incentives are available to program participants.

53. Reference: Exhibit B-1, Page 235, Part III Section C Tab 3 – Alternative Energy Solutions – Hydronic

up to 25 per cent and a maximum of $500. For 2010 spending will equal $778 thousand and for 2011 spending will equal $1.6 million for a two year total of $2.3 million.

53.1. Please identify how such systems might be employed to change the economic competitiveness of natural gas.

Response:

Natural gas is economically competitive from an operating cost perspective with other energy sources used for heat. Terasen Gas hopes to encourage the use of hydronic natural gas-based systems, seeing them as inherently desirable based on their adaptability, as is discussed in the paragraph below. The Company is proposing incentives intended to overcome the high capital barrier for these systems. It would be reasonable to expect the unit cost of hydronic systems to decline over time, reflecting an increase in the capacity of installers of such systems and a decrease in the cost of materials, bringing the overall capital cost of the systems down, and accordingly changing the economic competitiveness of natural gas.

Only hydronic based systems are easily adaptable to other sources of energy. While these systems are still more expensive than the electric alternative, use of hydronic systems allows a building to be more readily integrated into district energy systems, supplemented by solar thermal systems during the winter or adapted to whatever future energy source provides heat. By providing incentives now and reducing the capital cost of the infrastructure we are not only making gas applications more competitive, we are "future proofing" the building to be adaptable for future energy sources and future generations.

53.2. Please identify the circumstance in which such innovation may be cost-effectively pursued and distinguish between new greenfield development and older neighbourhood retrofit.

Response:

It should be noted that the reference above is misnamed; the page and budget amounts referenced in the Information Request are not for Alternative Energy Solutions in the larger sense, where TGI is owning and operating an energy system, but rather for incentives for programs for Innovative Technologies more along the lines of the Terasen Utilities' historical DSM programs. The response below addresses a distinction between new building

construction, and retrofitting these innovative technologies into existing buildings, rather than between new greenfield development and other neighbourhood retrofit.

In new buildings, natural gas is cost-effective from an ongoing operating perspective; however, as noted in the response to CEC IR 1.53.1, the capital cost for natural gas hydronic heating systems may not be competitive with capital costs for other types of systems. However, cost effectiveness is not the only factor that determines if a developer installs a hydronic system. As noted in CEC IR 1.36 of the ROE and Capital Structure Application, there are many factors that must be considered when putting in a heating system. A hydronic system may be installed in a new building when the developer believes that they can sell the building for more with such a system than they could with another type of system. Incentives help reduce the upfront capital costs and therefore would make a new building project with a hydronic heating system more competitive. See also CEC IR 1.53.1.

In older buildings, retrofitting with hydronic baseboards is possible, although not as common as replacing the original heating system with a new system identical to that being replaced. Again, incentives will help to lower the capital hurdle and make it more likely that the owner will install a hydronic system. Further, the owner is installing a system that will not only be cost-effective to operate, it is easily adaptable to other sources of energy.

53.3. Is this expenditure plan really just some level of R&D to gain real experience or is this a step forward on a strategy aimed at changing the economics and competitiveness of energy planning for communities?

Response:

It should be noted that the reference above is misnamed; the page and budget amounts referenced in the Information Request are not for Alternative Energy Solutions in the larger sense, where TGI is owning and operating an energy system, but rather for incentives for programs for Innovative Technologies more along the lines of the Terasen Utilities' historical DSM programs. The programs as outlined in the referenced section are pilot programs, designed to gather information to determine whether the technology should be subject of a larger program, and to find out what kinds of incentives will spur uptake for these technologies, which are in most cases new enough to be considered innovative from the perspective of most customers.

In-building Hydronic systems, such as those described in the reference above, are a step toward preparing buildings to be "integration ready" for community energy systems, which enhances the economics and competitiveness of community energy systems. The Terasen Gas incentives proposed would help with the cost effectiveness of the systems and promote greater

use of hydronic systems. As stated in the response to CEC IR 1.53.1— only hydronic systems are easily adaptable to other sources of energy. Whether it is under-floor or radiant baseboards, hydronic systems can easily be integrated into district energy or supplemented by solar thermal systems during the winter. By providing incentives we are "future proofing" buildings with hydronic heating systems.

54. Reference: Exhibit B-1, Page 235, Part III Section C Tab 3 – Alternative Energy Solutions – Combo

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.

54.1. Can these Combination systems also be connected to baseboard hydronics?

Response:

No, hydronic baseboards operate at optimal efficiency when the supply water temperature is 180°F. Combination systems are not designed to operate at this relatively high temperature.

55. Reference: Exhibit B-1, Page 236, Part III Section C Tab 3 – Alternative Energy Solutions – Solar Thermal

construction for an average new single family detached home. Solar thermal domestic water heating at present costs about $8,000 for an average home and can be used as a supplement to the existing hot water tank to supply roughly half of the yearly water heating energy requirements.

55.1. Is solar thermal anywhere near cost competitive at this level of investment?

Response:

No, solar thermal pre-heat systems as are being proposed in this Application are not cost competitive in terms of pay-back at an incremental capital cost of $8,000. However, with grants available through Solar BC, NRCan and other incentives[5], as well as the proposed incentives from TGI, the effective incremental cost for this technology can be reduced to $3525 and fuel cost can be reduced by $144 annually[6]. Simple pay-back can be achieved in just less than 25 years and 21 tonnes of GHG emissions can be avoided[7]. While from a purely financial return on investment standpoint this technology is not cost competitive with conventional gas hot water tanks, customers have shown that they are willing to pay more for a green energy source (at Dockside Green for example). As such, Terasen Gas believes there will continue to be more solar installations in the future; not providing an incentive to this relatively new technology because it is currently not cost competitive is not a valid reason to not provide incentives if the goal is to reduce consumption and lower GHG emissions.

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[5] $1000 SolarBC discount, Livesmart Rebate $125, EcoEnergy Rebate $1250, PowerSense Rebate $300 and Home Reno Tax Credit (approx) $800

[6] Based on a single family dwelling with four occupants in the Lower Mainland at current of $9.77/GJ x 14.8 GJ's replaced by solar

[7] GHG savings based on 0.7 tonnes/year x project life of 30 years; all numbers including simple payback are based on Retscreen analysis using default values for a family of 4 using Vancouver airport weather data. Retscreen is a Natural Resources Canada software program for evaluating alternative energy projects. The output from the Retscreen analysis of solar thermal is below.

RETScreen Energy Model - Heating project

Heating project

Technology		Solar water heater				
Load characteristics						
Application		☐ Swimming pool ☐ Hot water				
	Unit	**Base case**	**Proposed case**			
Load type		House				
Number of units	Occupant	4				
Occupancy rate	%	100%				
Daily hot water use - estimated	L/d	240				
Daily hot water use	L/d	240	240			
Temperature	°C	50	50			
Operating days per week	d	7	7			
☐ **Percent of month used**						
Supply temperature method		Formula				
Water temperature - minimum	°C	7.5				
Water temperature - maximum	°C	12.5				
	Unit	**Base case**	**Proposed case**	**Energy saved**	**Incremental initial costs**	
Heating	MWh	4.1	4.1	0%		
Resource assessment						
Solar tracking mode		Fixed				
Slope	°	50.0				
Azimuth	°					
☐ **Show data**						
Solar water heater						
Type		Glazed			$ 3,525	*See technical note*
Manufacturer		Viessmann				*See product database*
Model		VitoSol 100 SH1				
Gross area per solar collector	m²	2.52				
Aperture area per solar collector	m²	2.33				
Fr (tau alpha) coefficient		0.72				
Fr UL coefficient	(W/m²)/°C	3.50				
Temperature coefficient for Fr UL	(W/m²)/°C²					
Number of collectors		2	2			
Solar collector area	m²	5.05				
Capacity	kW	3.27				
Miscellaneous losses	%	5.0%				
Balance of system & miscellaneous						
Storage		Yes				
Storage capacity / solar collector area	L/m²	75				
Storage capacity	L	350.1				
Heat exchanger	yes/no	No				
Miscellaneous losses	%					
Pump power / solar collector area	W/m²					
Electricity rate	$/kWh					
Summary						
Electricity - pump	MWh	0.0				
Heating delivered	MWh	2.5				
Solar fraction	%	60%				
Heating system						
☐ Project verification		**Base case**	**Proposed case**			
Fuel type		Natural gas - GJ	Natural gas - GJ			
Seasonal efficiency		60%	60%			
Fuel consumption - annual	GJ	24.6	9.8	GJ		
Fuel rate	$/GJ	9.772	9.772	$/GJ		
Fuel cost	$	240	96			

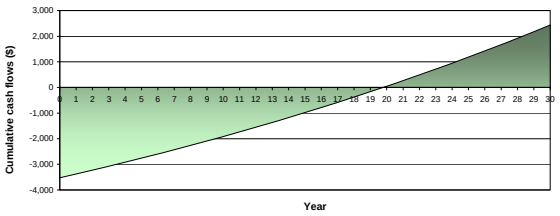
Emission Analysis

GHG emission					
Base case	tCO2	1.2			
Proposed case	tCO2	0.5			
Gross annual GHG emission reduction	tCO2	0.7			
GHG credits transaction fee	%				
Net annual GHG emission reduction	tCO2	0.7	is equivalent to	0.1	Cars & light trucks not used
GHG reduction income					
GHG reduction credit rate	$/tCO2				

Financial Analysis

Financial parameters			
Inflation rate	%	2.0%	
Project life	yr	30	
Debt ratio	%		
Initial costs			
Heating system	$	3,525	100.0%
Other	$		0.0%
Total initial costs	$	3,525	100.0%
Incentives and grants	$		0.0%
Annual costs and debt payments			
O&M (savings) costs	$		
Fuel cost - proposed case	$	96	
Other	$		
Total annual costs	$	96	
Annual savings and income			
Fuel cost - base case	$	240	
Other	$		
Total annual savings and income	$	240	
Financial viability			
Pre-tax IRR - assets	%	3.4%	
Simple payback	yr	24.4	
Equity payback	yr	19.8	

Cumulative cash flows graph



56. Reference: Exhibit B-1, Page 237, Part III Section C Tab 3 – Alternative Energy Solutions – Ground Source Heat Pumps

GSHP systems are more costly than gas or electric systems and can add upwards of $10,000 to $20,000 to the cost for average new home construction. GSHP can be used as the primary source of energy to heat a building; however they do require a back-up source of energy such as a gas fired boiler.

56.1. Are GSHPs anywhere near cost competitive at this level of investment?

Response:

No, GSHPs are not cost competitive in terms of pay-back, given current incremental capital costs and energy prices. While from a purely financial return on investment standpoint this technology is not cost competitive with conventional in-building heating and cooling systems, customers have shown that they are willing to pay more for green energy sources (at Dockside Green for example). As such, Terasen Gas believes there will continue to be more installations of GSHPs in the future; not providing an incentive to this relatively new technology because it is not currently cost competitive is not a valid reason to not provide incentives, if the goal is to reduce consumption and lower GHG emissions.

56.2. What sort of market is already developing for this technology?

Response:

There is little solid data on market penetrations for GSHP. Natural Resources Canada's 2006 data, the most recent available, indicates that heat pumps *of all types* have about a 1.7% share[8]. It should be noted that this figure includes Air Source Heat Pumps; anecdotal evidence would indicate about a 10: 1 split between Air Source and Ground Source Heat Pumps, which would put GSHP at about a 0.17% share.

It would appear that the determining factor for existing GSHP owners is environmental responsibility with financial factors holding a lower priority. The existing market for GSHP's is environmentally conscious home and building owners who will pay a premium for this technology. The incentives proposed are intended to increase the speed of market penetration for this technology by lowering the capital barrier for those customers who may be "on the fence" due to the poor payback scenario for this technology.

[8] Source: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/tablestrends2/res_bc_21_e_3.cfm?attr=0

56.3. What does Terasen see as its role in subsidizing this new alternative energy solution?

Response:

TGI sees providing incentives for ground source heat pumps ("GSHP") as being essentially the same as providing incentives for other energy efficiency initiatives in that it encourages the efficient use of energy. While this is a pilot program, the goal is to reduce energy usage, and by providing incentives for GSHP, customers may be more likely to install this system and therefore, energy usage would drop. This is consistent with the Act, specifically the definition below:

> **"government's energy objectives"**
>
> (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;

And further reinforced with the following definition;

> **"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

TGI therefore believes its role is to encourage the adoption of clean or renewable energy as it will reduce the energy demand a public utility must serve.

57. Reference: Exhibit B-1, Page 249, Part III Section C Tab 3 – Alternative Energy Solutions – NGV

become redundant. We request approval of the deferral treatment of compression equipment costs and expenses. The Transportation Service and the Compression and Refueling Service, as proposed in this Section of the RRA, complements the existing NGV service and results in a comprehensive natural gas fuel service across the value chain which offers customers solutions in managing transportation costs and reducing GHG emissions. The rate proposals also benefit existing customers through the more efficient use of our delivery infrastructure.

57.1. If there is a benefit to existing customers through more efficient use of the delivery infrastructure, what is that benefit, how much is it and why would Terasen provide that to existing customers for free and defer costs to future customers?

Response:

Yes. TGI believes there is a benefit to existing customers associated with NGV. We are anticipating that new NGV customers will bring a flat load profile (relatively high load factor) to the system. This will benefit all existing customers because an increased, flat load will better utilize the distribution system and distribute the delivery cost across a greater volume of natural gas resulting in lower delivery costs for all customers.

To clarify, delivery rates are trending up in part because of the decrease in natural gas consumption from the industrial sector and due to energy conservation efforts by the general public. This overall reduction in consumption or load means the load factor is decreasing and a flat load helps increase overall utilization. A decreasing load factor means that the costs to operate and maintain the piping system are spread across a lower natural gas volume causing the delivery rate to rise. A good analogy is if 4 people were taking a cab ride that costs $20 it would cost them $5 each, if 2 people jump out then the ride is paid by 2 people costing $10 each. If you add 2 people, then the costs are just over $3 each.

The Company is proposing a deferral account for the NGV initiatives in recognition that it is in the early stage of market development and as such it is not confident of the number of compressor installations that will occur over the period of the RRA and therefore both capital and revenue numbers are unknown. TGI believes that it is therefore not appropriate to put these costs into rates until after the period of the RRA.

58. Reference: Exhibit B-1, Page 250, Part III Section C Tab 3 – Alternative Energy Solutions – Biogas

in BC in a Pilot Phase of limited scope. In particular, TGI seeks approval to proceed with biogas upgrading projects and biogas/biomethane purchase agreements during the 2-year RRA period, provided that two conditions have been satisfied:

- the combined costs of upgraded biomethane (i.e., total raw biogas and upgrading costs) from each project are below a threshold price of $15 per GJ; and
- the combined annual output of the biogas projects on stream is less than 0.5 PJ.

58.1. Why would Terasen proceed with these limitations rather than a more direct market test?

Response:

The two limitations set out in the Application and noted in the question are constraints on the pilot phase for Biogas Upgrading projects for which TGI is seeking Commission approval. During the Biogas Pilot Phase the annual cost of service for upgraded biomethane will be recovered from all Terasen Gas' core market sales and unbundled customers through the Midstream Cost Recovery Charge in their rates. Since biogas upgrading projects are expected to be small volume in comparison to typical natural gas supply agreements, and upgraded biomethane is expected to be more costly than natural gas is currently, TGI is seeking approval in the pilot phase for a simplified approval approach for Biogas Upgrading projects rather than going through a full CPCN review process or a detailed review of an energy purchase agreement. TGI believes it is appropriate to put limits on the customer rate impact during the biogas pilot phase and that is the combined purpose of the two conditions.

As set out in pages 252- 254 of the Application, TGI is also in the process of developing a "green gas" market offering for future implementation. After the green gas market offering is implemented it is anticipated that the customers of that offering will be paying for the costs of green gas. For the reasons why TGI believes its proposed approach of proceeding with a limited pilot phase of biogas supply and upgrading projects while it develops its green gas market offering is appropriate, please see the response to BCUC IR 1.35.4.

58.2. Why wouldn't Terasen proceed where it has a market identified and contracted to take the Biogas at a specified price and be willing to proceed on the basis of covering its delivery cost and the cost of the upgrading with the balance going to the biogas supplier?

Response:

TGI has begun to plan and intends to conduct market research and surveying of customers on a "green offering" in the fall of 2009, which will assist in identifying the scope of the market. However, TGI believes that the pilot phase is another important step before designing rates for a "green offering" (the model advanced in the question is a type of rate design). An important initial purpose of the Biogas pilot phase is to validate the technical feasibility of biogas upgrading and in the process gain understanding of the overall expected costs of producing upgraded biomethane.

Until TGI has gained some operational knowledge in this area and done the market research with respect to a green gas offering TGI is unable to comment on whether the approach set out in the question would work. However, TGI's initial assessment is that a rate design that established a "green rate" open to customers is likely preferable to the model suggested in the question. First, the contract model advanced in the question would represent a somewhat piecemeal approach to matching supply and demand for biogas. Second, it is TGI's expectation that biogas producers would be reluctant to commit to a project where their revenue stream was highly uncertain by being based on a residual amount after upgrading and connection costs. In this case the biogas producer would have to absorb fluctuations in TGI's cost of upgrading (as well as fluctuations in the producer's own production costs). There would be further uncertainty in biogas producer's revenue stream by virtue of the fact that the prospective purchaser might be unwilling to commit to a price for biomethane for a suitably long period of time. If the purchaser, for example, was only willing to commit to a price for one year while the biogas producer was making investments on a 5 to 10 year basis then the producer would have uncertainty in its revenue stream after the first year.

In sum, TGI believes that the development of a "green offering" is a key step in fostering development of the biogas and biogas upgrading as a new renewable energy source in BC. TGI will be in a position to assess alternative rate designs once the pilot and market assessment have been undertaken.

58.3. Is this because Terasen was anticipating a sale of biogas at prices in relationship to volatile natural gas markets and would like to be able to strike a fixed rate to provide the biogas supplier certainty for its investment?

Response:

TGI believes in general that being able to offer fixed prices to biogas suppliers either for raw biogas (where TGI is doing the upgrading) or for upgraded biomethane (where a third party is doing the upgrading) will be an important element in advancing the development of biomethane as a renewable resource in BC. The biogas producers that TGI expects to be dealing with (such as municipalities for wastewater treatment plants and landfills, and agricultural developers) will be seeking a stable revenue stream and fair return on their investment. TGI expects that such parties would be highly averse to having large swings in the profitability of their investments in biogas capturing facilities because of pricing arrangements being tied to natural gas commodity pricing.

Please see also the response to BCUC IR 1.35.2.

58.4. Does Terasen believe that there may be economies of scale which may be shut out by a .5PJ limit?

Response:

It is a possibility that a larger project could develop within the next two years for which the 0.5 PJ per year volume limit on the pilot phase would impose a constraint. However, TGI is not aware at this time of any large projects that would be expected to develop within the 2010-2011 RRA period in a way that the 0.5 PJ limit would pose a problem. The 0.5 PJ per year limit constrains the amount of annual biomethane production under the pilot phase in order to limit the cost exposure of TGI's customers. If a large project came about that pushed the annual supply volumes over the 0.5 PJ limit, TGI would make a special application to the Commission for that project. TGI expects that such an application would either justify that project's inclusion in the pilot phase or propose other particular treatment as warranted by the circumstances.

Also, TGI's parallel development of a green gas market offering may be sufficiently advanced that it has been implemented by the time a larger scale biomethane supply project is developed and on-stream. If that is the case, the costs and volumes from the larger scale project would be rolled into the overall supply pool supporting the green gas offering.

58.5. Would it not make sense anticipate selling the biogas as an electric heating displacement under a fuel switching arrangement and thereby set the maximum price Terasen could go to in relation to the BC Hydro LTAP evidence of long run marginal cost of new supply being in the $120/MWh range less a conservation and efficiency profit margin?

Response:

When TGI adopted the BC Hydro RIB Step 2 rate as the reference pricing point for establishing the maximum price to be paid for biomethane consideration was given to biomethane being a substitute for residential electric space heating (see page 258 of the Application) and a possible energy source to displace new marginal electricity supply. While reference to a more recent marginal cost of new electricity supply, such as the $120/MWh evidence from BC Hydro's LTAP proceeding, was considered, TGI concluded that the more practical alternative was to use the RIB Step 2 rate as a publicly-available Commission-approved reference point for the biomethane maximum price calculation. The RIB Step 2 rate is also derived from the cost of new electricity supply, albeit from the results of a call for power in the recent past.

58.6. Alternatively the BC Hydro Power Smart programs have individual unit cost values some of which range up into this same range so would it not make sense to displace a more expensive BC Hydro Power Smart program with an alternative Biogas heating replacement?

Response:

TGI believes that the concept of having biomethane displace more expensive BC Hydro Power Smart programs is worth consideration, however all parties with an interest in an initiative of this nature, such as TGI, BC Hydro, customer groups and others would need to be convinced of the merits and cooperate in the development and implementation. Possibilities such as these fall more into the area of marketing opportunities for biomethane and will be given consideration, along with other possible marketing opportunities, as TGI develops its green gas market offering.

The pilot phase for which TGI is seeking approval in the Application will permit TGI to validate the technical feasibility of biogas upgrading and establishing the initial supply volumes at a modest level. At this early stage in the development of this new renewable resource it is not known whether adequate supply can be developed for a market offering of reasonable size. As a result, the green gas market offering may need to be a staged and/or targeted process, at least initially. The sequence in a staged offering, including where displacement of higher cost Power Smart programs might appropriately fit, is still to be determined. The possibility of

developing a green feedstock for gas-fired electricity generation in the province (Burrard Thermal, Island Cogeneration Project and Fort Nelson) is another area that is worthy of consideration; however the sequence and priority of supplying one market segment or another will depend on various factors.

58.7. Eventually would Terasen anticipate contracting for Biogas based on its costs of supply in a competitive market process once a market is established and better understood?

Response:

TGI agrees that it would be appropriate to establish competitive processes for biogas/biomethane supply and demand once the market is established and better understood. The rapid evolution currently of the policy context affecting biogas, in BC and elsewhere, for energy, GHG emissions and climate change, as well as uncertainty in the development timelines for biogas supply and demand, make it difficult to predict when such a point will be reached. As stated on page 252 of the Application, TGI believes it has an important leadership role to play in BC in the development of this new renewable resource and also in the development of a market for renewable green gas supply and demand.

59. Reference: Exhibit B-1, Page 261, Part III Section C Tab 3 – Alternative Energy Solutions – Biogas

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

59.1. While the .5PJ would represent less than .5% of the overall MCRA purchase would it be correct to say that the impact on customer rates would be driven by the difference in price between Terasen's cost of gas and the contracted price for the biogas methane?

Response:

Yes, the difference in price between TGI's cost of gas and the contracted price for the biomethane will be a driver of the impact of the biogas Pilot Phase on customer rates. The

annual volume of contracted biomethane will be the other driver. It should be noted that the rate impact from the pilot phase is expected be a temporary phenomenon of short duration until TGI begins to market green gas directly to interested customers. After that the incremental costs of the biomethane acquisition and production will be paid by the participants in the green gas market offering.

The maximum rate impact of the Pilot Phase, if all biomethane volumes were at the $15/GJ cap and the 0.5 PJ/year volume threshold was reached, would be in the range of $0.035/GJ to $0.04/GJ. This would amount to an annual bill increase for a residential customer in the range of 0.25% to 0.3%. It is unlikely that all contracted volumes will be at the $15/GJ cap and the 0.5 PJ annual volume limit may not be reached so that customer rate impact of the Pilot Phase is likely to be less than 0.25%. (The cost of gas assumed in these calculations is $7.00/GJ per BCUC IR 1.1.3 meaning the calculations are based on an $8.00/GJ difference between that price and the proposed $15/GJ price cap on biomethane.)

59.2. Would it be likely that the impact on Midstream Cost Recovery Rates would be closer to half the .5% impact proportion of the total?

Response:

Please see the response to CEC IR 1.59.1

59.3. Would it be likely that the impact as a percentage of customer's annual bills might be closer to half that again?

Response:

TGI agrees that the impact of the biogas Pilot Phase on customers' gas bills is very minor. Please see the response to CEC IR 1.59.1 for the specific estimates.

59.4. Would it be fair to say that these proposed pilot projects would have a relatively imperceptible impact on customer's bills?

Response:

Yes. TGI believes even if the maximum volume of biogas is brought onto the system, the *maximum* customer bill impact of the Pilot Phase of 0.25% to 0.3% (per the response to CEC IR 1.59.1) is reasonable and relatively imperceptible.

60. Reference: Exhibit B-1, Page 270, Part III Section C Tab 3 – Alternative Energy Solutions – District Energy Systems

In both of 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 the best fits their needs. The customer pays for the system and its operation over time at a rate that is acceptable to them, but which does not unduly impact the rates of other TGI customers.

60.1. The specific customer pay model would appear to relieve other customers of concerns about subsidizing specific customer applications. Does Terasen expect that its proposed levelizing of costs would represent the only element of this model which would cause impacts on other customers?

Response:

TGI agrees that the customer pay model relieves other customers concerns about subsidizing specific alternative energy projects. The levelizing of costs however, does not represent a risk to or impact to existing customers.

A levelized rate setting mechanism is a method of smoothing out the rates a customer group pays over time. It is a method to create a rate that ensures that there is not an unrealistic barrier to entry for new customers wishing to attach to the system. It is typically used in new large capital intensive utility projects and is designed to generally keep rates levelized so that initial customers attaching to the system do not pay significantly higher rates than those attaching later once capital has depreciated and there are more customers to shoulder costs. However, over the life of the asset, the customers of the project will have paid for all costs of the project.

This is similar to the TGI main extension ("MX") test mechanism whereby the economics of the main are analysed over a 20 year period, in this case using a postage stamp rate. On a main extension, generally, the there are not enough customers in the first couple of years to pay for all the costs of the main, however, over time, enough customers attach that all costs of the main are paid. In other words, the Profitability Index ("PI") is one.

The levelized alternative energy rate setting mechanism accomplishes the same thing as the TGI MX test. Therefore there is not a risk to or a negative impact to existing customers. Note that there is a positive impact to existing customers as the alternative energy economic test includes overhead loading which will result in a higher rate for the alternative energy customer than without overhead loading. As such alternative energy customers will help reduce TGI overhead and marketing related costs.

60.2. Does the proposed levelizing of costs when applied to customer projects of very different cost magnitude mean that some projects would have substantially more impact on other customers than other projects and if so should there be a limit?

Response:

Please see response to CEC IR 1.60.2. TGI does not believe that there is a negative impact on existing gas customers as a result of levelized rate setting for alternative energy customers. Therefore projects of a very different magnitude will not have a negative impact on existing gas customers. For this reason, TGI does not believe a limit should be placed on the size or cost of projects that can be approved through this streamlined process.

61. Reference: Exhibit B-1, Page 279, Part III Section C Tab 4 – Customer Demand

Table C-4-2: Annual Consumption (GJ/yr) by Housing Type – Significant differences

Housing Type	2007 Normal
Single Family Dwelling	94
Multi-Family Dwellings	60
Vertical Subdivision	23

Source: 2008 Residential End Use Study

61.1. Please supply the Average Number of family units per Multi-Family Dwelling & per Vertical Subdivision.

Response:

Multi-Family Dwellings are considered to be individually metered units within a multi-unit residential dwelling, which typically includes duplexes, row houses, and townhouses. Vertical Subdivisions are considered to be individually metered suites within a multi-storey building, typically also having a common meter that provides make up air and/or hot water to all of the suites in the building.

When TGI captures the customer, it does so on a "per service" (or "per meter") basis. Given that, when a Multi-Family Dwelling is attached, each individual family unit would be served by a single meter and therefore TGI captures only one single family unit being served by that meter. For Vertical Subdivisions, the common meter that provides make up air and/or hot water would be serving each of the family units within that building, and therefore TGI captures the total number of family units in the building.

Therefore, TGI is only able to estimate the average number of family units per Vertical Subdivision. For 2008, the average number of family units per Vertical Subdivision is 80, and the average number of stories per Vertical Subdivision is 7. Multi- family dwellings as defined by TGI are customers that have their own meter and therefore are reported as an individual customers just like a single family home.

61.2. Please supply the Average Extension and Connection Cost to Service each of these housing types.

Response:

Due to difficulties in obtaining the information required to respond to this IR, TGI was unable to complete this IR at the time of filing. The response will be provided as soon as possible, but anticipated no later than Friday, August 21, 2009.

62. Reference: Exhibit B-1, Page 300, Part III Section C Tab 4 – Customer Demand

Should there be a material difference between the forecast filed in the RRA and the results of the industrial customer survey, it is anticipated that an update will be filed as soon as practical.

62.1. Has the industrial customer survey been completed and has there been any difference from what is contained in the Application.

Response:

The 2009 Industrial Survey has only recently been completed and TGI is currently in the process of re-evaluating its industrial forecast, using this additional data, to determine whether or not there is a material difference to the forecast contained in the Application. A comparison of year-to-date actuals versus projections is provided in TGI's response to CEC IR 1.31.1.

63. Reference: Exhibit B-1, Page 315, Part III Section C Tab 4 – Gas Transportation

As the approval of the $3.6 million per year debiting of the MCRA and crediting of the delivery margin revenue account extends until November 1, 2010, part way through the effective term of this Application, Terasen Gas hereby seeks approval from the Commission to extend the continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million per year by a period of ten years until November 1, 2020. Terasen Gas believes this treatment of costs and

63.1. If this treatment were not approved by the Commission what treatment would Terasen expect to apply?

Response:

Terasen Gas believes that the extension of the $3.6 million per year debiting of the MCRA and crediting of the delivery margin revenue account through November 1, 2020 is appropriate as SCP is expected to be an important part of the Terasen Gas resource portfolio on a long term basis. SCP provides diversity of supply, operational flexibility, and is currently cost effective relative to alternative supply options, such as additional contracting for T-South service on Westcoast pipeline. As discussed in the Terasen Gas Application for Approval of Transactions with respect to Southern Crossing Pipeline and Inland Pacific Connector dated June 1, 2005 (and approved by the Commission per Order No. G-98-05 dated October 6, 2005) utilizing the BC Hydro SCP capacity as part of its portfolio of Midstream resources meets the objectives of the Annual Contracting Plan and provides for optimal benefits to customers.

The proposal to continue the accounting treatment of debiting of the MCRA and crediting of the delivery margin ensures that all customers will realise the benefit of using SCP as part of the midstream portfolio by reducing the delivery margin. If the Commission did not approve this treatment, then only customers who contribute to MCRA costs would realise the benefit. In other words, if this treatment whereby Midstream (via the MCRA) effectively pays the delivery margin for the capacity were not approved by the Commission, MCRA costs would be lower and the delivery margin higher by $3.6 million per year.

63.2. Why has this treatment been made applicable until November 1, 2010?

Response:

The $3.6 million per year debiting of the MCRA and crediting of the delivery margin revenue account has been made applicable until November 1, 2010 in recognition that the initial term of the BC Hydro transportation service agreement and peaking agreement with Terasen Gas, based on 52.2 MMcfd of SCP capacity, which would have expired November 1, 2010 after the

primary term of 10 years. This is consistent with the Commission Decision regarding the Application by Terasen Gas for Approval of Transactions Related to the Southern Crossing Pipeline and Inland Pacific Connector per Order No. G-98-05, dated October 6, 2005.

Terasen Gas has requested that this treatment be made applicable for another 10 years until November 1, 2020 as SCP is an important part of the Terasen Gas resource portfolio over the long term, enabling reliability, diversity and cost effective gas supply service for core customers. Terasen Gas believes the ten year extension is not an unreasonable period of time to allocate to long term portfolio resources.

63.3. What is the utilization of SCP at this time through to November 1, 2010?

Response:

SCP continues to serve its primary purpose to meet the peak and seasonal needs of its firm system sales customers as was demonstrated recently during the period December 13, 2008 to January 5, 2009, when British Columbia experienced a bout of prolonged cold weather resulting in high gas flows in all of the Terasen Utilities' operating regions. The consumption loads peaked on December 19th and 20th at just over 1 PJ each day. The temperature in the Lower Mainland was 30% colder on average (19.5 actual degree day vs. 15.0 normal degree day temperature) compared to normal resulting in higher deliveries to core customers by about by 35% during the three week cold snap.

The SCP load factor was 79% during this extended cold snap and 103% on December 19th and 20th as the Company had increased the line pack on the system in advance of the two coldest days.

In addition to meeting the peak and seasonal needs of firm system sales customers, SCP is also optimized by the Company as a means to help reduce gas costs. During periods when the available capacity exceeds actual customer demand, the Company captures the price differential between two markets by utilizing SCP. For example, the Company buys gas at Station 2 and sells gas at Kingsgate, moving gas west to east across SCP. The Company also buys gas at the Nova Inventory Transfer ("NIT") in Alberta and sells gas at Huntingdon, moving gas east to west across SCP. The difference between the purchase and sale prices, less variable costs goes towards reducing gas costs.

Terasen Gas is also working with Spectra Energy to combine un-contracted T-South capacity with west to east SCP capacity to provide a new, Spectra Energy firm transportation service from Station 2 with the flexibility to deliver to Huntington or Kingsgate.

In the future, the Company will continue to utilize SCP in the manner described above.

64. Reference: Exhibit B-1, Page 317, Part III Section C Tab 5 – Cost of Gas

Gas cost related deferral accounts decrease the volatility in rates caused by fluctuations in gas prices thereby providing greater rate stability for customers. The various gas cost deferral accounts capture

64.1. Have the deferral accounts been successful in decreasing volatility in rates for customers?

Response:

Terasen Gas believes that the gas cost deferral accounts, in conjunction with the existing Commission approved gas cost recovery rate adjustment mechanisms, have provided decreased rate volatility for customers. Further, Terasen Gas believes that the hedging program works in a complimentary manner with the gas cost deferral accounts as used in conjunction with the gas cost rate adjustment mechanisms to reduce rate volatility for customers.

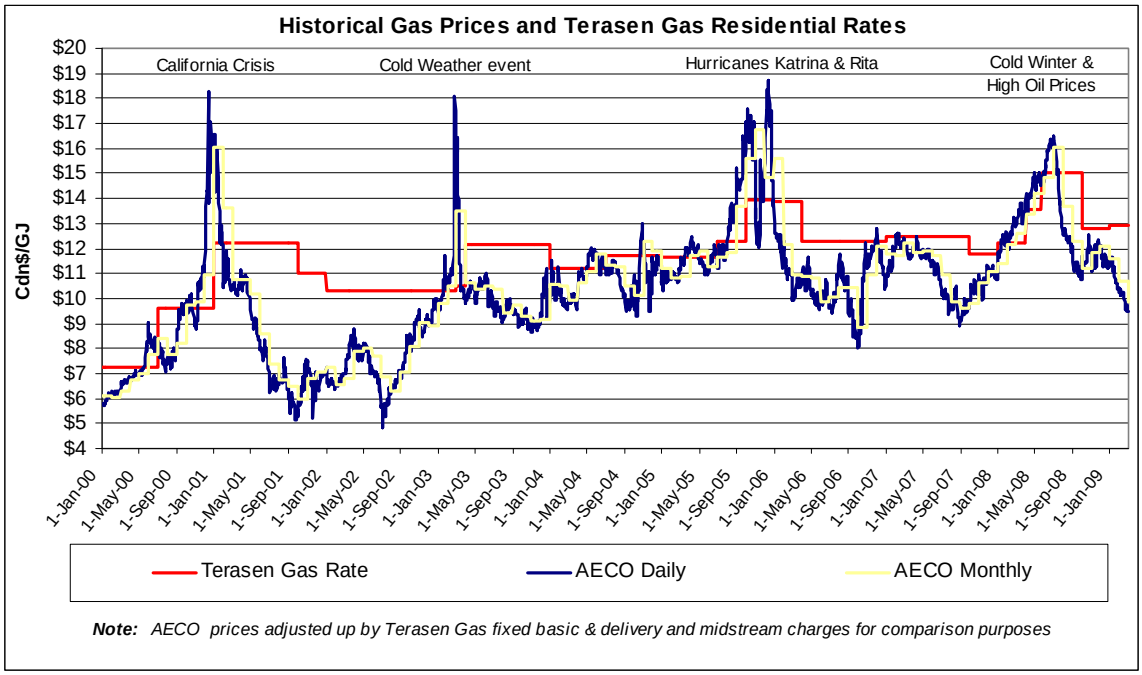
As discussed in the response to BCUC IR 1.66.1, the gas cost deferral accounts capture variances between the actual gas costs and the forecast gas costs as recovered in rates, and the deferral mechanisms in place are, pursuant to Commission guidelines and directives, reviewed quarterly, allowing these variances to be recovered from, or refunded to, customers as part of future rates forecast over a twelve month period. The gas cost deferral accounts ensure that the actual gas costs incurred, including any differences from the forecast gas costs embedded in rates in effect at that time, are borne by customers while the quarterly review and rate setting mechanism, based on the twelve month future outlook, provides the decreased volatility in rates.

Terasen Gas submits quarterly gas cost reports to the Commission which provide the gas cost deferral account variances recorded to date, the forecast gas costs and recoveries, and Terasen Gas' recommendations for rates. Terasen Gas' commodity cost recovery rate is typically adjusted when the ratio of the forecast recoveries for the next 12 months compared to the forecast gas costs for the next 12 months period, including any surplus or deficit balance in the deferral account at the end of the current period, falls outside of the 0.95 to 1.05 deadband range, though noting that all rate changes are subject to approval by the Commission.

64.2. How much stability in rates does Terasen believe is necessary or valuable to customers?

Response:

Terasen Gas believes some degree of stability in rates, certainly less volatility than that present in the natural gas marketplace, is necessary and valued by customers. Evidence of this was confirmed in February 2005 when Terasen Gas engaged a research company to survey customers regarding their tolerance for volatility. The survey results confirmed that while customers will tolerate some volatility (annual bill increase of up to 17% in a year) the level of tolerance is certainly less than the volatility that has occurred in the recent past in the natural gas market. Terasen Gas' market-based rate offering, including the use of hedging and deferral accounts, protects customers from the full impact of market price volatility and price spikes. The following graph illustrates the volatility reduction which has been provided by the Terasen Gas rate (for residential customers per Lower Mainland Rate Schedule 1) relative to AECO market prices, which have been adjusted upward to account for the Terasen Gas fixed basic and delivery charges, and the midstream rate for comparative purposes.



64.3. Please confirm that this stability in rates is not only a function of deferral accounts but is also a function of natural gas price hedging as well.

Response:

As discussed in the responses to BCUC IR 1.66.1 and CEC IR 1.64.1, it is not the gas cost deferral accounts themselves that provide the decreased volatility in rates, but rather the overall gas cost deferral and recovery rate adjustment mechanisms. The gas cost deferral accounts capture variances between the actual gas costs and the forecast gas costs embedded in rates, and the quarterly review and rate adjustment mechanisms that help to reduce the volatility in rates.

Terasen Gas believes that the hedging program, and the gas cost deferral accounts, in conjunction with the gas cost recovery rate adjustment mechanisms, work in a complimentary manner to help decrease rate volatility caused by fluctuations in gas prices.

64.4. Could rate stability for customers be maintained by making greater use of the deferral account and reducing the contribution of hedging?

Response:

It is possible that a similar degree of rate stability for customers could be maintained by making greater use of the gas cost deferral accounts, in conjunction with the gas cost recovery rate adjustment mechanisms, and reducing the contribution of hedging. However there would be increased risk of incurring significant build-ups in the gas cost deferral accounts, which is not desirable from the perspective of either customers or the Company. One of the objectives of the existing Commission approved gas cost recovery rate adjustment mechanisms is to avoid incurring large deferral balances within the gas cost deferral accounts. As discussed in the response to BCUC IR 1.66.1, Terasen Gas believes that the hedging program and the deferral accounts, used in conjunction with the gas cost recovery rate adjustment mechanisms, work in a complimentary manner, rather than as substitutes, in reducing rate volatility for customers.

The objectives of the hedging program are to moderate the volatility of market prices and the resultant effect on rates, improve the likelihood that natural gas remains competitive with electricity, and reduce the risk of regional price disconnects. The hedging program accomplishes these objectives through layering in hedges over time per a predefined schedule extending out 36 months but the implementation also includes accelerated hedging when favourable price targets are reached. The result is that the hedging implementation affects the underlying commodity cost of gas over an extended period of time which is flowed through to customers via rates.

The deferral accounts utilized by Terasen Gas capture variances between the actual gas costs and the forecast gas costs as recovered in rates and the deferral mechanisms enable these variances to be recovered from, or refunded to, customers as part of future rates. Thus, while the deferral accounts, used in conjunction with the gas cost recovery rate mechanisms, decrease the volatility in rates, they do not affect the underlying commodity prices embedded in the cost of gas, which the hedging program does.

Therefore, the hedging program affects the underlying cost of gas and is implemented on a rolling 36-month schedule which provides longer term stability. The gas cost deferral accounts and gas cost recovery rate mechanisms do not affect the underlying incurred cost of gas but do smooth the effects gas cost volatility has on rates. Deferral account deficits / surpluses are typically recovered from / refunded to customers over a future 12-month period.

To conclude, Terasen Gas believes that the hedging program and the deferral accounts, in conjunction with the gas cost recovery rate mechanisms, work in a complimentary manner, rather than as substitutes, in reducing rate volatility for customers, and that the combined effect on rate volatility reduction is important given the highly volatile nature of natural gas prices in recent years.

64.5. Could the smoothing mechanism in these deferral accounts be improved?

Response:

This question is difficult to answer because the concept of "improving" the smoothing mechanism is somewhat subjective. Nevertheless, Terasen Gas believes the rate smoothing provided through the gas cost deferral accounts, used in conjunction with the existing Commission approved gas cost recovery rate adjustment mechanisms, have served customers well in the past and will continue to do so in the future.

The mechanism currently in place has been established pursuant to Commission guidelines and directives, and includes a formula-driven calculation to determine the extent to which current rates are expected to under or over recover the forecast gas costs during the next 12-month period. Although the rate change mechanism includes a mechanistic calculation and uses a 95% to 105% deadband, the mechanism also retains discretion in terms of the gas cost recovery rates applied for and the gas cost recovery rates approved. Further, Terasen Gas emphasizes that changes to the mechanism will not affect the underlying cost of gas, which is ultimately passed through to customers, and that all rate changes are subject to approval by the Commission.

Included as Attachment 64.5, is a copy of the one page Commission document entitled, "Attributes of Deferral Account and Gas Cost Rate Setting Methodologies" (the "Attributes

Document") which was issued as Appendix II of Commission Letter No. L-5-01, dated February 5, 2001. Terasen Gas believes that the discussion presented within the Attributes Document remains valid, and provides a fairly concise overview of the main objectives of gas cost deferral accounting and rate setting methodologies, and also provides some relevant discussion related to the often conflicting nature between, and within, those objectives. In addition, Terasen Gas believes the potential for such conflict may not only increase when there is a persistent upward or downward trend in natural gas prices, but also when there is a high degree of volatility in the natural gas prices, as experienced in recent years.

To conclude, Terasen Gas believes the concept of improving the "smoothing mechanism" is highly subjective in nature due to the various, and often conflicting, objectives of the gas cost deferral accounts and gas cost recovery rate setting methodologies as discussed within the Attributes Document, and Terasen Gas further believes the current, Commission approved, gas cost deferral accounts and rate setting mechanisms are appropriate and provide value to customers by adequately balancing the objectives of rate stability, price transparency, size of deferral account, and efficiency of process.

64.6. What criteria would Terasen use to evaluate optimal results from the use of these deferral accounts?

Response:

Please refer to the response to CEC IR 1.64.5.

64.7. Is the 12 month clearing and plus or minus 5% mechanism providing optimal results and how do we know?

Response:

Please refer to the response to CEC IR 1.64.5.

65. Reference: Exhibit B-1, Page 323, Part III Section C Tab 5 – Cost of Gas

Given the volatility in the natural gas marketplace in recent years, Terasen Gas believes it prudent and appropriate to continue to hedge the pricing associated with company use gas through Sumas fixed price swaps to provide protection against possible unfavourable movements in natural gas prices in the future. Terasen Gas, as requested within its letter to the Commission dated May 29, 2009,

65.1. Would a deferral account approach provide protection against possible volatility and avoid the net cost of hedging?

Response:

As discussed in the response to CEC IR 1.64.4, the gas cost deferral accounts used in conjunction with the gas cost recovery rate adjustment mechanisms decrease the volatility in rates but they do not affect underlying commodity prices, the way hedging does. Therefore, to provide protection against possible volatility associated with the pricing of Company Use Gas and fix the underlying price, Terasen Gas has implemented hedging for the price of the Company Use Gas for 2010 and 2011 per the Commission acceptance of the Terasen Gas request to hedge Company Use Gas in Letter No. L-44-09 dated June 11, 2009.

When prices ultimately settle for this period, hedging costs or gains may result, and there may not be any costs incurred for hedging Company Use Gas. Regardless, Terasen Gas believes that, given the volatility in the natural gas marketplace and potential for prices to move up in the future, this is a prudent approach in managing costs on behalf of customers.

65.2. Can Terasen demonstrate that its hedging of gas cost is profitable?

Response:

Terasen Gas believes the value of the hedging program lies in successfully meeting the objectives of the Price Risk Management Plan. The primary objectives of the Plan are to improve the likelihood that natural gas remains competitive with electricity over the term of the plan, moderate the volatility of market gas prices and their effect on rates for customers, and reduce the risk of regional price disconnects (i.e. wherein Sumas pricing separates significantly from Station #2 or AECO hub pricing in periods of high demand). Terasen Gas believes these objectives have been met and have served customers well, providing value through rates significantly less volatile than prices in the natural gas marketplace at a reasonable cost that is competitive, at least on a variable cost basis, with electricity rates. While the hedging program

has resulted in a range of annual hedging gains and costs over the past number of years, this is not indicative of the probability of future hedging gains or costs nor does Terasen Gas believe this is relevant to the success of its hedging program or the value to customers. Terasen Gas does not consider profitability a factor in the success of its hedging program, and it should be recognized that pursuit of profitability in hedging requires "beating the market" and taking unnecessary risks which may not be to the benefit of customers.

66. Reference: Exhibit B-1, Page 324, Part III Section C Tab 5 – Cost of Gas

Terasen Gas therefore requests approval from the Commission for this methodology of accounting for volume and cost variances within the MCRA account effective January 1, 2010.

66.1. For the last 5 years, how much have the charges to O&M been for the volume and cost variances, which Terasen is now proposing to have charged through the MCRA?

Response:

For the past 5 years, the volume and cost variances have been negative, meaning that the actual volumes ended up lower than forecast. These variances have benefited customers in the past through lower O&M costs than forecast. Terasen Gas is proposing that any positive or negative volume variances in 2010 and 2011 be charged to customers by flowing them through the MCRA.

Table 1.66.1: Company Use Gas Variances – Actual Volumes Below Forecast

	2004	2005	2006	2007	2008
Volumes (GJ)	(57,730)	(66,488)	(31,394)	(21,351)	(6,952)
Average Unit Price (incl. tax)	$ 4.58	$4.48	$5.24	$5.67	$5.06
Dollars	$ (264,403)	$ (297,866)	$ (164,505)	$ (121,060)	$ (35,177)

(amounts exclude Facilities Company Use Gas)

67. Reference: Exhibit B-1, Page 347, Part III Section C Tab 6 – PBR

Another useful comparison in establishing 2009 as the appropriate base for forecasting 2010 and 2011 expenses, is to consider what the 2010 and 2011 O&M would have been under an extension of the PBR Agreement for two more years, and used the 2009 formula O&M as the base. Under this scenario (calculation shown in Table C-6-2 below), the formula O&M would have been calculated at $210.6 million in 2010 and $217.2 million in 2011, assuming no efficiency factor. This demonstrates that the nominal restated O&M expense forecasts for those years of $206.8 million and $214.6 million respectively are less than the amounts that would have been forecast under the extension of the PBR Agreement for two more years.

67.1. Under PBR would Terasen have shared 50% of the difference between the formula O&M and the actual?

Response:

Assuming the terms of the current PBR Agreement were extended for 2010 and 2011, in this hypothetical scenario, TGI would share 50%, as would customers, of the difference between the formula O&M and the actual O&M.

67.2. Assuming in this case that the actual was the same as the Terasen RRA forecast above would the 50% sharing have been on the difference between the numbers provided above?

Response:

The 2010 and 2011 O&M forecasts discussed in the referenced paragraph have been adjusted downward from the proposed forecasts for items that would be considered "exogenous factors" under the current PBR agreement. Therefore, in order to achieve that level of O&M, for the purposes of determining the amount for sharing, TGI would have to receive approval from the Commission for exogenous factor treatment for those items. If that approval was received, the sharing would be calculated on the difference between the numbers referenced in the above paragraph.

68. Reference: Exhibit B-1, Page 347, Part III Section C Tab 6 – O&M

Table C-6-1: O&M per Customer is Lower in 2010 and 2011 than 2003

	Decision 2003	Projection 2009	Forecast 2010	Forecast 2011
Total Gross Nominal O&M Expenses ($ millions)	$ 181.7	$ 195.1	$ 209.6	$ 219.1
Total Gross Real O&M Expenses ($ millions)	$ 204.7	$ 195.1	$ 205.7	$ 210.8
Average Number of Customers	770,368	833,798	839,949	845,633
Real O&M per Customer	**$ 266**	**$ 234**	**$ 245**	**$ 249**

68.1. In part is there pressure for increasing O&M costs because of the reduced capital expenditures caused by reduced customer additions?

Response:

TGI confirms there is pressure in increasing O&M costs because of reduced customer additions. Distribution is impacted by variations in synergies as construction and operations activities increase and decrease from year to year. The recent pronounced downturn in new customer additions caused significant loss of synergies and a corresponding increase to first response standby costs in 2008 and 2009.

Distribution has reduced the magnitude of the cost pressure in 2010 and 2011 by sharply curtailing work plans previously assigned to installation contractors and by ramping up long term capital programs, specifically hazard mitigation. Distribution will continue to proactively manage this area to minimize financial impacts. (Source: page 366 of the RRA)

69. Reference: Exhibit B-1, Page 375, Part III Section C Tab 6 – O&M

An impact of changes in both energy policy and customer need for more energy knowledge (described previously on page 350) is that customers are increasingly asking for more detailed reports on their usage of gas over past periods, ranging from one to five years. Customers seeking this service are government related bodies such as municipalities, health authorities and government housing, as well as commercial and industrial customers. While some of this information is available online for customers, that information is not sufficiently detailed. It neither contains read dates and degree days, nor is it designed to aggregate consumption from consolidated billed customers.

69.1. At some point would it make sense for Terasen to implement a fee policy for information and consultation to be charged over future billings?

Response:

Please see TGI's response to BCUC IR 1.97.1.

70. Reference: Exhibit B-1, Page 417, Part III Section C Tab 7 – Taxes

Effective January 1, 2009, the Company has adopted changes to Canadian GAAP in respect of Section 3465 Income Taxes. This has resulted in the inclusion in rate base of both future income tax liabilities and an equal and offsetting amount for a regulatory future income tax asset, as discussed in Part III, Section C, Tab 11, Accounting and Other Policies. The adoption of IFRS is also discussed in the same section.

70.1. Does this mean that Terasen would be earning a return on equity for this component of the rate base?

Response:

The future income tax liability deducted from rate base is equal to the regulated future income tax asset included in rate base. Since the two amounts offset each other, they have zero impact on rate base, and therefore TGI does not earn an equity return on the net of these two offsetting amounts.

71. Reference: Exhibit B-1, Page 342, Part III Section C Tab 8 – Rate Base

Terasen Gas has continued to use the NGV Conversion grant program, as approved by Commission Order No. G-98-99. The Company records the actual amount of grants in the NGV Conversion Grants deferral account, and amortizes them in rates over five years. Any variances between the forecast level of expenditures and actual expenditure levels will be amortized in rates beginning in 2012.

71.1. Does Terasen have any evidence that the provision of these grants has been a net benefit to customers over time?

Response:

Yes, we have evidence which demonstrates that grants offer a net benefit to customers in the transportation sector. Our sales process involves working with customers and providing a detailed value proposition including a financial analysis which indicates how long it will take to pay back incremental costs associated with conversion to natural gas. The sample evaluation below uses a simple payback model to justify for the conversion of a lift truck or fork lift fleet.

Step 1	CAPITAL COSTS			
	Base Cost of Conversion	$	4,000	
	Less Terasen Incentive	$	2,500	
	Conversion cost	$	1,500	per forklift
	Number of forklifts		40	
	Estimated forklift life		15	years
	Other vehicle conversions	$	40,000	
	Estimated total conversion cost	$	100,000	fleet total
Step 2	Current Fuel Costs			
	Propane Costs (Estimate)		0.50	$/l
	NG Costs (Current cost)		0.38	$/l
	Savings per liter	$	0.12	$/l
	Estimated Annual Consumption		800000	l
	Estimated Annual Propane Cost	$	400,000	
	Estimated Annual NG Cost	$	304,000	
	Estimated Annual Savings	$	96,000	
	Simple Payback (years)		**1.04**	**Years**
	Total Savings (remaining forklift life)	**$**	**1,440,000**	

By offering grants under Rate Schedule 6 – Natural Gas Vehicle Service and the proposed Rate Schedule 26 – Natural Gas Vehicle Transportation Service, customers will benefit as grants assist in reducing the up front conversion costs and the payback period.

As part of our sales efforts, we believe the promotion of grants will assist in attracting new NGV customers which in turn will bring a flat load profile to the system. This will benefit all existing customers because an increased, flat load will better utilize the distribution system and distribute the delivery costs to a greater number of customers resulting in lower delivery costs for all customers.

72. Reference: Exhibit B-1, Page 492, Part III Section C Tab 11 – Accounting and Other Policies

For departments where there are identifiable, direct activities in support of capital activity (Distribution, Transmission, Marketing, Business Services, Regulatory and Finance), managers of the department were asked to conduct a detailed analysis to estimate the portion their employees' time related to capital activity but not being charged to capital directly. For these employees, a proportionate share of all their costs excluding labour time already directly charged to capital was then allocated to the capitalized overhead pool.

For support departments where a primary driver of their costs is influenced by the number of employees in the organization (Information Technology Support, Facilities Management, Human Resources Advisory), the departments' costs were allocated to the overhead pool based on the number of full time equivalent employees working on capital activity at Terasen Gas.

Insurance premiums paid for commercial liability policies were apportioned to the overhead pool based on proportion of dollars spent on Capital projects versus O&M activities (i.e. 30 per cent), as these costs are incurred for the Terasen Gas organization as a whole. The remaining corporate overhead costs, including future employee benefits and TGVI Shared Services recovery, were then allocated to the overhead pool based on a composite average calculated percentage.

Terasen Gas believes the recommended overhead capitalization rate incorporates IFRS requirements. Costs such as training costs which were previously included in capitalized overhead have now been excluded as part of the determination process in order to conform to IFRS.

72.1. Are the above description of the overhead capitalization methodology and the description in the KPMG report in Appendix H-3 from Page 8 to 14 the most complete ones available in the Application?

Response:

Yes, that is correct.

72.2. Does Terasen have a working paper spread sheet showing the department by department overhead allocation application and if so could this please be provided?

Response:

Please refer to Attachment 72.2.

72.3. The above description appears to rely on department manager estimates of the proportion of time spent on capital versus operating activities?

Response:

For those departments where direct activities in support of capital activity could be identified, managers were asked to estimate the portion their employees' time related to capital activity but not being charged to capital directly. Please see the response to CEC IR 1.72.4.

72.4. Does this approach meet Terasen's criteria for (a) being free from bias (b) being stable over time (c) reliable (d) accurate

Response:

Managers are considered the best source of accurately assessing the level of capital support activities occurring within their department. Their assessments are based upon knowledge of the business and key processes, the nature and extent of capital support being offered, and the allocation of resources within their department. Managers frequently collaborated with their staff as a means of augmenting their decisions.

KPMG independent review of TGI's approach and methodology is summarized in the report filed as Appendix H-3. In their assessment (please refer to pages 20 -21), KPMG concluded TGI's criteria for Freedom from Bias, Stability and Accuracy of the Underlying data were satisfied. In addition, page 31 of KPMG's report states, "KPMG finds the methodology to be reasonable and in accordance with internal policy, external guidance from the regulators and industry standards practices related to overhead capitalization."

72.5. Please provide a list of the Gross O&M costs which are excluded from eligibility to be allocated to overhead and capitalized and the amounts excluded for 2009, 2010 and 2011.

Response:

Using the 2009 budget data, the overhead allocation excluded $54.5m from the capitalized overhead allocation. $47.8M related to TGI's Outsourced Customer Care Contract, $5M related to Bad Debt Management and $1.7M related to training expenses. These expenses were considered to have no direct relationship to capital activities.

As indicated in TGI's response to BCUC IR 1.195.2, this information for 2010 and 2011 is not available. The Overhead Cost Allocation calculation is the final result of a lengthy and exhaustive process that was performed utilizing 2009 budget data. TGI believes the overall composite overhead capitalization of 8% is appropriate for 2010 and 2011 with no material differences expected in the upcoming two years.

72.6. Please provide a detailed description of the costs attributed to the President. Why is the President deemed to have nothing to do with the capital expenditures of the corporation?

Response:

Included in the President costs, as shown on page 12 of Appendix H-3, are the President and CEO and Executive Assistant Salaries, along with their supporting expenses. In addition, the President and CEOs' Office centralizes certain corporate wide costs items such as external legal fees and industry association fees. The President and CEO Office provided overall management and leadership for the utility. This Office ensures that resources are employed efficiently and effectively across all departments and is responsible for the strategic growth of the organization and overall guidance and management. Under IFRS, these activities are considered ineligible for capitalization as these costs are considered too far removed from capital projects to establish some reasonable causal link or association with a specific capital activity.

72.7. Please provide a detailed description of the costs attributed to the Human Resources and Operational Governance Service. Why is Human Resources assumed to have nothing to do with capital projects?

Response:

Included in the Human Resources and Operations Governance, as shown on page 12 of Appendix H-3, are all costs as described on Page 391, Part III, Section C, Tab 6, with the exception of HR Advisory Services. The HR Advisory Services group is shown as a separate line on the table on page 12 of the KPMG report.

Human Resources and Operations Governance with the exception of HR Advisory Services is considered too far removed from capital projects to establish some reasonable causal link or association with a specific capital activity under IFRS.

72.8. Please provide a breakdown of the capital expenditures between labour, materials and other purchased items. Please provide a breakdown of the gross O&M between labour, materials and other purchased items.

Response:

The following amounts are from the 2009 budget data. 2009 budget data was used for the purpose of this study, given that it represented the most current data to utilise for the numeric calculation of the Overhead Cost Allocation.

Expenditures (millions)	**Capital**	**O&M**
Labour	22.0	90.1
Materials	13.8	5.5
Contractors	24.7	59.3
Vehicles	2.5	4.7
Other	20.2	34.6
Total	83.2	194.2

72.9. With such a major capital project involving customer care enhancement and significant customer additions, is it possible that asking managers in 2009 to make allocations will miss the forward impact of the planning for the customer care enhancement capital activity?

Response:

The impact of the customer care project was considered as part of the capitalized overhead review. Managers were asked to review and document their respective department's capital activities for the period 2009 to 2011, including any changes as a result of large capital projects. Through TGI's review process, it was determined that the customer care enhancement project would not have a significant impact on the capitalized overhead. This is because managers and support staff working on the project will be charging directly to the project through capital orders.

72.10. Because capital costs are direct charges for capital work presumably they will represent the direct labour of people assigned to capital projects. In departments where there is a mix of capital and operating work this may cause the holiday time, organizational time, safety & training time among other items to be included in the operational expenditures weighting versus the capital weighting. How does Terasen ensure that this bias is not reflected in the overhead capitalization estimates?

Response:

The labour rate used for direct charge-out of time, is the same for both O&M and capital activities and includes an appropriate share of vacation/holiday, sick time and other organizational time. This process ensures for those departments where there is a mix of capital and operating work, there is no bias reflected in the in the overhead capitalization estimates.

73. Reference: Exhibit B-1, Page 220, Part III Section C Tab 2 – Revenue Requirement - Accounting Changes

Table C-2-1: Revenue Requirements Reflect Needs of Stakeholders[142]

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 (Section C, Tab 13-1, Schedule 2 and 3, Column 6, Line 15)		**$ 27.9**		**$ 21.9**	**$ 49.8**

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PART III: SECTION C – TAB 2: REVENUE REQUIREMENTS AND RATE PROPOSALS PAGE 220

73.1. Is the tax impact of depreciation shown above a consequence that the fact that depreciations rates are set independently of CCA rates and so whenever one or the other has rate changes there is a separate impact to be shown?

Response:

No, the tax impact of depreciation as shown in Schedule 1 is not related to CCA rates. The tax impact related to depreciation, as shown on Schedule 1, reflects the revenue requirement impact that the change in depreciation has on the tax expense.

Depreciation is a non tax deductible expense; therefore, it must be added back to net income in the calculation of the tax expense. If the depreciation expense is increasing, this will result in a higher tax expense and correspondingly increase the revenue requirement. Alternatively, if the depreciation expense is decreasing it will result in a lower tax expense and correspondingly decrease the revenue requirement.

For example, if depreciation expense (not tax deductible) increases by $5 million and the tax rate is 30%, revenues (which are taxable) need to increase by $7.1 million to have no effect on income, as shown below:

Revenues	$ 7.1
Depreciation expense	(5.0)
Pre-tax income	$ 2.1
Tax expense	(2.1)
Net Income	$ 0.0

Tax expense would be calculated on the $7.1 million in revenue, but not on the $5 million depreciation expense deduction, so tax expense would be $7.1 million x 30% = $2.1 million.

73.2. From the revenue requirement effects before accounting standard changes can Terasen confirm that these would have resulted in an approximately 3% decrease in rates followed by an approximately 4% increase in rates?

Response:

The impact on delivery rates of the revenue deficiency or surplus before accounting standard changes results in an approximate delivery rate decrease of 2.8% in 2010 and an increase of approximately 4.4% in 2011 (cumulative increase of 1.6% in 2011).

74. Reference: Exhibit B-1, Page 223, Part III Section C Tab 2 – Revenue Requirements – Depreciation Changes

(5) Depreciation and Amortization Expense

As discussed in Part III, Section C, Tab 11, Accounting and Other Policies and also Part III, Section C, Tab 8, Rate Base, there have been significant changes to the calculation of depreciation expense as a result of IFRS. This has resulted in an increase to depreciation expense of $22.7 million. Of this, $20.8 million is related to an updated depreciation study and a further $1.9 million results from a change in the timing of commencement of depreciation. Additions in 2010 and 2011 have resulted in higher depreciation expense of $3.7 million in 2010 and a further $2.3 million in 2011. Since the impacts on depreciation of the accounting changes are not deductible for income tax purposes, the total impact on revenue requirements for these items needs to be grossed up. The revenue requirement impact of all of these changes is an increase of $35.4 million in 2010 and a further $2.8 million in 2011.

In addition, amortization expense has declined $2.2 million in 2010 but then increased $4.0 million in 2011. Both of these amounts are after-tax, so the impact to revenue requirements is as stated.

74.1. Would it be fair to say that the depreciation and amortization expense changes are responsible for something over 7% of the total cumulative 9.4% rate increase Terasen is seeking?

Response:

When all of the depreciation and amortization expense changes (excluding the rebasing) are considered, the result is a cumulative 2011 revenue requirement impact of approximately $39.9 million. This impact translates into an approximate cumulative delivery rate increase of 7.52% in 2011.

($ Millions)	2011 Cumulative RR Impact	Cumulative Rate Impact
After Tax Change in Depreciation from GPIS Additions/Retirements	$ 6.0	1.13%
Change in Amortization	1.8	0.33%
After Tax change in Depreciation Rates	21.2	3.99%
After Tax change in Depreciation Commencement	1.9	0.35%
Tax Impacts of Depreciation Changes	9.1	1.71%
Total Revenue Requirement Impact of Depreciation & Amortization Expense Changes	**39.9**	**7.52%**

74.2. Would it be fair to say that changes in the timing of in service dates for capital investments causes approximately 1% of the total cumulative 9.4% rate increase Terasen is seeking?

Response:

Changes in the timing of in service dates for capital investments do not have an impact on the rate increase that Terasen Gas is seeking; the only change for forecast purposes in the timing of in service dates for capital investments is in relation to the treatment of CPCN additions to gross plant in service as discussed in Section C, Tab 8, page 422 of the Application. In this RRA, there are no CPCNs that are in progress in either 2010 or 2011, so there is no impact on rate base of this change. However, TGI is requesting a change to the timing of the commencement of depreciation, to which the $1.9 million relates.

The $1.9 million impact of the change in the timing of the commencement of the depreciation is approximately 0.4% of the total cumulative 9.4% rate increase that Terasen Gas is seeking. As noted in section C, Tab 11, page 481 of the Application, this change reflects the commencement of depreciation expense when assets are available for use instead of the current practice whereby depreciation commences at the beginning of the following year.

75. Reference: Exhibit B-1, Page

(3) Implementation of Recommendations

Implementation of the recommended rates, which are set out in Table C-11-2 below, that were developed using the Average Service Life ("ASL") depreciation methodology and are expected to be compliant with IFRS requirements, would increase the average composite depreciation rate for Terasen Gas plant from approximately 2.7 per cent to 3.4 per cent [refer to line 62 of Table C-11-2], with the annual depreciation expense increasing by approximately $21 million. Since depreciation expense is not tax deductible, the Company's revenue requirement increases by approximately $29 million. This excludes the effects on depreciation expense of additions to PP&E, the proposed IFRS changes related to the commencement of depreciation and differences in classification of items as capital or expense, discussed earlier in on page 485 under Depreciation. For a summary of the total revenue requirement impact of depreciation changes see Part III, Section C, Tab 2, Revenue Requirements, Table C-2-1.

75.1. Table C-11-2 contains the current depreciation rates and the proposed depreciation rates and estimates for depreciation for both as well as the difference showing the approximate $21 million increase. A foot note says plant data for the above is as of January 1, 2010. Please confirm that all of the data in the table shows the proposed depreciation for 2010.

Response:

The proposed total annual depreciation expense for 2010 is approximately $113 million and is shown in Section C, Tab 13, Depreciation and Amortization Continuity Schedule - Schedules 48 and 49.

Table C-11-2 shows the forecasted annual depreciation expense increase of approximately $21 million which is calculated using January 1, 2010 projected gross asset balances and the recommended depreciation rates as contained in the recent Gannett Fleming depreciation study. Not included in the 2010 depreciation expense increase outlined in Table C-11-2 are the effects on depreciation expense of additions to PP&E for 2010, the proposed IFRS changes related to the commencement of depreciation and differences in classification of items as capital or expense.

75.2. Of all of the categories in the table six represent virtually all of the cause of the depreciation increases. The following is a summary of the six. Please confirm that this is correct.

Plant Category	Current Rate	Current Life	Proposed Rate	Proposed Life	Depreciation Increase Amount	Percent Increase
DS Service	2.00%	50yrs	3.38%	30yrs	$ 8,858,734	69%
DS Meters	3.57%	28yrs	5.31%	19yrs	$ 3,215,853	48%
Masonry Structure	1.50%	67yrs	4.37%	23yrs	$ 2,397,236	191%
DS Meas/Reg Adds	3.00%	33yrs	5.72%	17yrs	$ 2,243,285	90%
DS Meter/Reg Install	3.57%	28yrs	5.21%	19yrs	$ 2.203,674	45%
DS Mains	2.00%	50yrs	2.26%	44yrs	$ 2,197,149	13%
					$21,115,931	

Response:

The six plant categories listed above represent the top six categories with the highest annual depreciation expense increase forecasted in 2010 as the result of adoption of the proposed depreciation rates outlined in the Gannett Fleming depreciation study.

For clarity, it is not correct to conclude that the percentage numbers under the columns titled "Life" represent just the Life of the Asset. They include provisions for both the Life of the Asset and Net Salvage costs. For example, the TGI depreciation rates as shown in Tables 1 and 2 of the Gannett Fleming report (reference pages III-5 and III-8) for Account 473 – Distribution Services are 2.25% related to Life and 1.13% for the recovery of net salvage (i.e. retirement costs) for a total of the 3.38% as indicated above.

Secondly, the depreciation rates for most accounts have not been modified for a number of years. As such, the accumulated depreciation reserve now contains a significant amount of historic gains/losses on transactions over the last decade. To recover these balances, Gannett Fleming has incorporated a component into the "Life" depreciation rate calculation over the remaining life of each account.

For the estimated average service life used in the depreciation rate calculations, please refer to Table 1 of the Gannett Fleming Report (reference pages III-5) under the column titled "Survivor Curve". The first two number of the survivor curve represent the average service life indication for the account. The second two digits represent the Iowa curve shape. A discussion of Iowa shapes is contained in the Gannett Fleming report starting at page II-3.

75.3. For the six categories above please provide the year by year plant additions and the year by year retirement data.

Response:

Please refer to Attachment 75.3 which contains the year by year plant additions and the year by year retirement data from 1999 – 2008 for the six asset classes - DS Services, DS Meters, Masonry Structure, DS Meas/Reg Adds, DS Meter/Reg Install and DS Mains.

75.4. Please provide the specific depreciation curve fitting and data used by Gannett Fleming to reach their conclusions.

Response:

As indicated in the Gannett Fleming depreciation study report, the average service lives were selected

> *"….based on judgment which considered a number of factors. The primary factors were the statistical analysis of data, current policies and outlook as determined during conversations with management and the field trip, and survivor curve estimates from previous studies of this company and other gas distribution companies." (Gannett Fleming report, page II-21)*

The average service life estimates for each of the six categories identified in CEC IR 1.75.2 were developed in accordance with the above procedures. Each of the six categories is further discussed below by Gannett Fleming with specific references to the Gannett Fleming report, highlighting the depreciation data and curves used by Gannett Fleming to reach their conclusions.

Account 473 – Distribution Services

The considerations used in the selection of the 55-R1 Iowa curve were discussed starting at page II-23 of the Gannett Fleming Report. The results of the retirement rate study are presented at page IV-40 through IV-43 of the Gannett Fleming report. The Life tables resulting from the Retirement Rate analysis (pages IV-41 to IV-43) indicated the plant exposed to retirement at each age interval from age 0.0 though to age 91.5. The life tables also indicate the actual retirements at each of the age intervals, and the actual retirement ratio at each of the age intervals.

From this observed data, the percentage of plant surviving at each of the intervals is also calculated and presented. The manner in which these calculations were made is discussed in detail at pages II-3 through II-19 of the Gannett Fleming report. The age surviving at each

interval (the last column of the Life tables presented at pages IV-41 through IV-43) were plotted on the graph presented at page IV-40 of the Gannett Fleming report.

The results of the retirement rate analysis as plotted on page IV-40 of the Gannett Fleming report were statistically fitted to each of the four families of Iowa curves to determine the statistically best fit. The Iowa 55-R2.5 was the best statistical fit to the entire observed life pattern. Operational interviews confirmed that the historic experience should be a good indicator of the future retirement pattern. Gannett Fleming then tested the historic retirement pattern to a group of industry peers to determine the reasonableness of the 55-R2.5 Iowa curve. The group of peers and the average life estimate for each is as follows:

- ATCO Gas - 52-R3.5
- Centra Gas Manitoba – 50-R2.5
- SaskEnergy – 55-R3
- AltaGas Utilities Inc. – 44-R4

Based on the above comparison to industry peers, the observed 55-R2.5 was deemed to be within an acceptable band of comparable utilities.

As the 55-R2.5 Iowa curve was based on the observed history of TGI, consistent with feedback provided by TGI management and operating staff and comparable to industry peers, the 55-R2.5 Iowa curve was recommended to represent the average service life pattern of Account 473 – Distribution Services.

Account 478.1 – Distribution Meters

The considerations used in the selection of the 25-R2 Iowa curve were discussed starting at page II-24 of the Gannett Fleming Report. The results of the retirement rate study are presented at page IV-61 through IV-62 of the Gannett Fleming report. The Life tables resulting from the Retirement Rate analysis (pages IV-61 to IV-62) indicated the plant exposed to retirement at each age interval from age 0.0 though to age 43.5. The life tables also indicate the actual retirements at each of the age intervals, and the actual retirement ratio at each of the age intervals.

From this observed data, the percentage of plant surviving at each of the intervals is also calculated and presented. The manner in which these calculations were made is discussed in detail at pages II-3 through II-19 of the Gannett Fleming report. The age surviving at each interval (the last column of the Life tables presented at pages IV-61 through IV-62) were plotted on the graph presented at page IV-60 of the Gannett Fleming report.

The results of the retirement rate analysis as plotted on page IV-60 of the Gannett Fleming report were statistically fitted to each of the four families of Iowa curves to determine the statistically best fit. The Iowa 25-R2 was the best statistical fit to the observed life pattern through age 30. It is noted that beyond age 30, the plant exposed to retirement becomes

immaterial when compared to the levels of plant exposed to retirement at younger ages. Therefore the observed life indications beyond age 30 were not considered in the average service life analysis. Operational interviews indicated significant changes in policy regarding the manner in which metering costs are capitalized. Based on these discussions, Gannett Fleming considered that the observed 25-R2 Iowa curve is reasonable at this time. Gannett Fleming then tested the 25-R2 Iowa curve to a group of industry peers to determine its reasonableness as follows:

- ATCO Gas - 25-R2.5
- Centra Gas Manitoba – 28-R3
- SaskEnergy – 31-R4
- AltaGas Utilities Inc. – 34-R2.5

Based on the above comparison to industry peers, the observed 25-R2.5 was deemed to be within an acceptable band of comparable utilities.

As the 25-R2.5 Iowa curve was based on the observed history of TGI, comparable to industry peers and meets the expectation of management and operating staff, the 25-R2.5 Iowa curve is recommended to represent the average service life pattern of Account 478.1 – Distribution Meters.

Account 482.2 – Masonry Structures

The results of the retirement rate study are presented at page IV-69 of the Gannett Fleming report. The Life tables resulting from the Retirement Rate analysis (page IV-69 indicated the plant exposed to retirement at each age interval from age 0.0 though to age 36.5. The life tables also indicate the actual retirements at each of the age intervals, and the actual retirement ratio at each of the age intervals. From this observed data, the percentage of plant surviving at each of the intervals is also calculated and presented. The manner in which these calculations were made is discussed in detail at pages II-3 through II-19 of the Gannett Fleming report. The age surviving at each interval (the last column of the Life tables presented at page IV-69) were plotted on the graph presented at page IV-68 of the Gannett Fleming report.

The results of the retirement rate analysis as plotted on page IV-68 of the Gannett Fleming report were statistically fitted to each of the four families of Iowa curves to determine the statistically best fit. The Iowa 25-R2 was the best statistical fit to the entire observed life pattern. Given that this account is uniquely componentized, there was no ability to test the results of the retirement rate analysis to industry peers. As such, the average service life as determined from historic experience resulted in the recommendation of the use of the 25-R2 Iowa curve for this account.

Account 477.1 – Distribution Meter and Regulator Additions

The considerations used in the selection of the 25-R2 Iowa curve were discussed starting at page II-26 of the Gannett Fleming Report. The results of the retirement rate study are presented at page IV-53 and IV-54 of the Gannett Fleming report. The Life tables resulting from the Retirement Rate analysis (pages IV-53 and IV-54) indicated the plant exposed to retirement at each age interval from age 0.0 though to age 44.5. The life tables also indicate the actual retirements at each of the age intervals, and the actual retirement ratio at each of the age intervals. From this observed data, the percentage of plant surviving at each of the intervals is also calculated and presented. The manner in which these calculations were made is discussed in detail at pages II-3 through II-19 of the Gannett Fleming report. The age surviving at each interval (the last column of the Life tables presented at pages IV-53 and IV-54) were plotted on the graph presented at page IV-52 of the Gannett Fleming report.

The results of the retirement rate analysis as plotted on page IV-52 of the Gannett Fleming report were statistically fitted to each of the four families of Iowa curves to determine the statistically best fit through to age 35. As indicated in the Gannett Fleming report at page II-26, only the retirement experience through to age 35 was considered in the selection of the average service life. The Iowa 25-R2 was the best statistical fit to the observed life pattern through to age 35. Operational interviews confirmed that the historic experience should be a good indicator of the future retirement pattern. Gannett Fleming then tested the historic retirement pattern to a group of industry peers to determine the reasonableness of the 25-R2 Iowa curve. The group of peers and the average life estimate for each is as follows:

- ATCO Gas - 15-R5
- Centra Gas Manitoba – 31-R2
- SaskEnergy – 38-R2.5
- AltaGas Utilities Inc. – 40-R4

Based on the above comparison to industry peers, the observed 25-R2 was deemed to be within an acceptable band of comparable utilities. As the 25-R2 Iowa curve was based on the observed history of TGI, consistent with feedback provided by TGI management and operating staff and comparable to industry peers, the 25-R2 Iowa curve was recommended to represent the average service life pattern of Account 477.1 – Distribution Meter and Regulator Additions.

Account 474 – Distribution Meter and Regulator Installations

The results of the retirement rate study are presented at page IV-45 and IV-46 of the Gannett Fleming report. The Life tables resulting from the Retirement Rate analysis (pages IV-45 and IV-46) indicated the plant exposed to retirement at each age interval from age 0.0 though to age 47.5. The life tables also indicate the actual retirements at each of the age intervals, and the actual retirement ratio at each of the age intervals. From this observed data, the percentage of plant surviving at each of the intervals is also calculated and presented. The manner in which

these calculations were made is discussed in detail at pages II-3 through II-19 of the Gannett Fleming report. The age surviving at each interval (the last column of the Life tables presented at pages IV-45 and IV-46) were plotted on the graph presented at page IV-44 of the Gannett Fleming report.

The results of the retirement rate analysis as plotted on page IV-52 of the Gannett Fleming report indicated a very significant amount of early retirement activity. Detailed review of the accounting data that has lead to this indication of early retirement are not reflective of the accounting practices going forward. As such, Gannett Fleming placed minimal reliance on the results of the retirement rate analysis for this account. Based on operational interviews, it was determined that the 30-R2 Iowa curve may provide for a better indication of future retirement pattern. However the occurrences of actual early retirements cannot be completely ignored. Gannett Fleming tested the reasonableness of the 30-R2 Iowa curve to a group of peers and the average life estimate for each is as follows:

- ATCO Gas - 45-R4
- Centra Gas Manitoba – 40-R4
- SaskEnergy – 55-R2.5
- AltaGas Utilities Inc. – 41-R3

Based on the above comparison to industry peers, Gannett Fleming views that the selected 30-R2 provides some recognition to the history of early retirements and trends towards the industry peer experience.

Account 475 – Distribution Mains

The considerations used in the selection of 60-R3 Iowa curve were discussed starting at page II-21 of the Gannett Fleming Report. The results of the retirement rate study are presented at page IV-48 and IV-49 of the Gannett Fleming report. The Life tables resulting from the Retirement Rate analysis (pages IV-48 and IV-49) indicated the plant exposed to retirement at each age interval from age 0.0 though to age 73.5. The life tables also indicate the actual retirements at each of the age intervals, and the actual retirement ratio at each of the age intervals. From this observed data, the percentage of plant surviving at each of the intervals is also calculated and presented. The manner in which these calculations were made is discussed in detail at pages II-3 through II-19 of the Gannett Fleming report. The age surviving at each interval (the last column of the Life tables presented at pages IV-48 and IV-49) were plotted on the graph presented at page IV-47 of the Gannett Fleming report.

The results of the retirement rate analysis as plotted on page IV-47 of the Gannett Fleming report were statistically fitted to each of the four families of Iowa curves to determine the statistically best fit. As indicted at page II-47, the historic indications for this account are that

plant begins to retire at a rapid rate at approximately age 50. As such the statistical Iowa curve fitting resulted in 63-R5 Iowa curve. The high mode was a direct result of the large ratio ratios at the end of the assets life. TGI had been previously using a 60-R2.5 Iowa curve for this account. Gannett Fleming views that the increase in mode to R5 would be too big of a change to make in one step. As such, Gannett Fleming recommended that an increase to an R3 mode is reasonable as a first step. Given the use of a lower mode (R3 versus the R5) a reduction is service life is required to recognize the assets that have been shown to survive beyond 70 years.

The Iowa 60-R3 was confirmed as reasonable by TGI operating staff. Gannett Fleming then tested the historic retirement pattern to a group of industry peers to determine the reasonableness of the 60-R3 Iowa curve. The group of peers and the average life estimate for each is as follows:

- ATCO Gas - 62-R2.5
- Centra Gas Manitoba – 65-R3
- SaskEnergy – 65-R3
- AltaGas Utilities Inc. – 55-R2

Based on the above comparison to industry peers, the observed 60-R3 was deemed to be within an acceptable band of comparable utilities.

75.5. Please provide some understanding as to why services might be showing a retirement experience that would justify a so much shorter life of 30 years.

Response:

As noted in the response to CEC IR 1.75.2, it is not correct to conclude based on the proposed annual depreciation rate of 3.38% that Distribution Services have an expected service life of 30 years only. Instead, as suggested by Gannett Fleming, the expected life for Distribution Services is 55 years based on the Iowa survivor curve 55-R2.5

Contributing to the noted increase from the current 2% annual depreciation rate to the 3.38% proposed is the increase to 1.13% for Net Salvage retirement costs incurred. Primarily driven by customer requests on the Lower Mainland to remove or deactivate existing services due to redundancy and demolitions as the result of development (i.e. larger lots getting subdivided and infill housing developments), TGI has been incurring retirement costs to abandon services lines. In addition, TGI has a program to specifically remove service lines where there is no intended use in the foreseeable future, where the meter has been removed, riser capped and tagged but is still a live gas service which poses a potential liability and risk to company and the public.

It is the recovery of these abandonment costs that is in part driving the increase in the depreciation rate for Distribution Services.

75.6. Could this experience have to do with older stock homes, which received natural gas service part way through their expected life and are now beginning to be retired and or replace, while newer homes which were provided with service are not experiencing anything like the same retirement or replacement rate?

Response:

As mentioned in the response to CEC IR 1.75.5, TGI has observed a trend in older single family structures, notably in the Lower Mainland, being demolished and re-developed into multi-family housing. This redevelopment activity and the resulting impact on TGI's service abandonment levels are driven by the demand for affordable housing and economic development cycles in the province.

75.7. Has Terasen done any investigation of this issue to isolate what may be causing the retirement experience, if so please provide all of the investigation and research results?

Response:

TGI has not conducted any investigation into possible causes of early retirement of services, beyond the anecdotal evidence it has at hand. Except for specific instances where TGI believes the distribution system / lines have deteriorated to a state where retiring and replacing the existing lines is warranted (i.e. CPCN Low Pressure System Renewal Project on Lower Mainland), TGI's Distribution Service retirement activities are driven primarily by customer requirements due to redundancy and for demolitions associated with new housing development, something which is beyond TGI's control.

75.8. Can Terasen confirm that this retirement experience is not a function of service line failure across all services?

Response:

TGI confirms that the retirement experience is not a function of a service line failure across all services. TGI has observed no issues with the polyethylene service lines it has installed to date. Where issues have been identified regarding steel service lines, TGI has proceeded to initiate repairs as required. In addition, please refer to response to CEC IR 1.75.7 for further discussion of possible reasons contributing to service retirements.

75.9. Could the earlier retirement experience be related in part to use of steel pipe and corrosion experience, which means pipe has to be replace, but is not affecting polyethylene piping currently being used?

Response:

No, corrosion of steel pipe is not materially contributing to increase in depreciation rate. As noted in the response to CEC IR 1.75.5, it is the recovery of abandonment costs that is in part driving the increase in the depreciation rate for Distribution Services.

75.10. Please provide some understanding as to why meters might be showing a retirement experience that would justify a so much shorter life of 19 yrs?

Response:

It is not correct to conclude based on the proposed annual depreciation rate of 5.31% that the category DS Meter has an expected service life of 19 years only. Instead, as indicated by Gannett Fleming in the response to CEC IR 1.75.4, the expected life for DS Meter is 25 years based on the Iowa survivor curve 25-R2.5 which is deemed to be within an acceptable band of comparable utilities.

The proposed 25 year service life is consistent with the previous recommendation back in 2004 when Gannett Fleming proposed a 4.78% depreciation rate that was reflective of a 25 year life and included a catch up component for the lower accumulated depreciation as the result of a longer service life for meters of 33 years assumed previously.

Back in 2004 and based on data at that time, TGI believed that on average its meters had an expected life of 28 years. As a result, TGI instead adopted a lower depreciation rate based on a 28 year life expectancy (3.57%) instead of the Gannett Fleming proposed rate of 4.78%.

The latest Gannett Fleming's study once again points to a slightly lower average service life of 25 years. The recommended depreciation rate of 5.31% incorporates a 25 year average service life and also includes a component for catching up for lower accumulated depreciation accrued previously. With TGI's decision to operate residential meters to the full life expectancy of 20 years without an attempt to extend the life expectancy through refurbishment (please refer to response CEC IR 1.75.11), the average service of the meter fleet may have to be shortened further from the 25 year average indicated. This issue will be reviewed further as part of the next depreciation study update.

It is this combination of events in the past that best explains the proposed increase in the depreciation rate from 3.57% to 5.31% for meters.

75.11. Can Terasen confirm that this experience is not related to meter failures across all meters?

Response:

TGI confirms that this experience is not related to meter failures across all meters. Please refer to response to CEC IR 1.75.10 for further discussion of the reason driving the proposed higher depreciation rate for meters.

Prior to 2006, TGI targeted an extended life expectancy of 28 years for its residential meters enabled by a refurbishment that occurred after 14 years of operation. However, throughout the past decade, the unit price for residential meters has remained relatively low in relation to labour costs associated with meter refurbishment. As such, the decision was made to operate residential meters to the full life expectancy of 20 years without an attempt to extend the life expectancy through refurbishment. Although, this strategy has proven to be a more cost-effective approach to meter management, it also has the effect of reducing the weighted average age of the overall meter fleet.

75.12. Has Terasen done any investigation of this issue to isolate what may be causing the retirement experience?

Response:

Please see the response provided to CEC IR 1.75.11.

75.13. Does Terasen have some meters, which are experiencing a greater frequency of failure?

Response:

In 2008, Terasen Gas uncovered the concern that residential meters installed during the late 1990's were showing signs of premature wear through the process of conducting accuracy tests as part of its annual performance sampling program. Although Terasen Gas has not experienced significant failures in absolute terms within this segment of the meter fleet, there has been a distinctly higher failure rate than would be expected for meters of this age. As such, Terasen Gas has adjusted the meter recall schedule to ensure these meters are removed from service in the time period in which they have reached their restated life expectancy.

Please refer to the responses for BCUC IR 1.170.1, 1.170.2 and 1.170.3 for an expanded description of the strategy related to the handling of these meters.

75.14. Does Terasen repair meters which have been pulled from service and if so are the repaired meters returned to service, and if so are these meter changeouts counted as retirement experience?

Response:

Please see the response to CEC IR 1.44.1, which explains that refurbishment of higher cost commercial and industrial meters is conducted by Terasen Gas but the relatively low purchase price of residential meters makes replacement of these meters a more cost effective option to refurbishment. Finally, only meters that are permanently removed from service are counted as retired meters.

75.15. Please provide a full description of all of Terasen's Masonry Structures.

Response:

Masonry Structures are brick/concrete exterior walls that would either be painted or have a stucco applied to them. The Masonry Structures that Terasen Gas owns are the buildings located in Kelowna, Penticton, Kamloops, Cranbrook, Surrey, Burnaby and Prince George. These structures are the company's regional/head offices that house the employees who operate and maintain the natural gas distribution and transmission systems, as well as warehouse the materials that are required.

75.16. Please provide some understanding as to how such structures might be showing a retirement experience that would justify a so much shorter life of 23 years?

Response:

As described in the response to CEC IR 1.75.4 and based on TGI retirement data, Gannett Fleming determined the Iowa 25-R2 curve indicating an approximate life of 25 average life was the best statistical fit to the entire observed life pattern. As outlined in the response to CEC IR 1.75.17 and 1.75.18, the data indicates the early retirements being observed are due to changing business needs for the use of the building and land and not related to the failure of the structures.

Given the limited amount of retirement data available for Masonry structures, the issue will be reviewed further as part of the next depreciation study update.

75.17. Can Terasen confirm that these structures are not failing across all structures in the system?

Response:

Terasen Gas confirms that the structures are not failing across all structures in the system.

In fact, there have been no significant Masonry Structures retirements since 2001. Prior to that, the retirements that did occur were not as the result of failing structures but instead due to the sale of properties on which the buildings were located (Cranbrook and Nelson offices) and the replacement of the Fraser Valley office buildings with upgraded facilities to meet the company's needs.

75.18. Has Terasen done any investigation of this issue to isolate what may be causing the retirement experience?

Response:

Terasen Gas has not done any investigation to isolate what may be causing the retirement experience. As indicated in the response to 75.17, the recent retirements that occurred had nothing to do with the failure of the structures but instead were due to changing business needs for the use of the building and land.

75.19. Does Terasen periodically have reasons to be removing these structures and if so are they being replaced or eliminated from service?

Response:

Please refer to the response to CEC IR 1.75.17.

75.20. Please clarify what the Measurement/Regulation Additions are and what the Meter/Regulation Installations.

Response:

To clarify, following is the definition of Measurement/Regulation Additions and Meter/Regulation Installations:

Measurement / Regulation Additions (Measuring and Regulating Equipment) - includes the cost of gate and regulating (pressure reducing) station equipment whose primary functions are to provide reduction in pressure to serve a distribution network and/or to monitor flow and consumption of gas.

Meter / Regulation Installations (House Regulators and Meter Installation) - includes the cost of house regulators whether actually installed or held in reserve. It also includes cost of labour and materials used and expenses incurred in connection with the original installation of house regulators and meters.

75.21. Please provide some understanding as to how such plant items might be showing a retirement experience that would justify a so much shorter life of 17 & 19 years?

Response:

For asset DS Meas/Reg Adds, it is not correct to conclude based on the proposed annual depreciation rate of 5.72% that the category has an expected service life of 17 years only. Instead, as indicated by Gannett Fleming in the response to CEC IR 1.75.4, the expected life for

DS Meas/Reg Adds is 25 years based on the Iowa survivor curve 25-R2 which is deemed to be within an acceptable band of comparable utilities. Contributing to the noted increase from the current 3% annual depreciation rate to the 5.72% proposed rate is adjustments required for the prior under-recovery of depreciation.

For asset DS Meter/Reg Install, it is also not correct to conclude based on the proposed annual depreciation rate of 5.21% that the category has an expected service life of 19 years only. Instead, as indicated by Gannett Fleming in the response to CEC IR 1.75.4, the expected life for DS Meter/Reg Install is 30 years based on the Iowa survivor curve the 30-R2. Based on comparison to industry peers, Gannett Fleming views that the selected 30-R2 provides some recognition to the history of early retirements and trends towards the industry peer experience. Contributing to the noted increase from the current 3.57% annual depreciation rate to the 5.21% proposed rate is adjustments required for the prior under-recovery of depreciation.

75.22. Has Terasen done any investigation of this issue to isolate what may be causing these items to experience such retirement rates?

Response:

For asset DS Meas/Reg Adds, TGI has not conducted any investigation into possible causes of early retirement. As indicated by Gannett Fleming in their discussion in response 75.04, the historic retirement pattern of these assets is reflective of a 25 year life which was deemed to be within an acceptable band of comparable utilities. The proposed 25 year life is not an indication of an early failure issue and instead represents an updating of the service life profile of the asset based on updated retirement experience.

For asset DS Meter/Reg Install, TGI has not conducted any investigation into possible causes of early retirement. As indicated by Gannett Fleming in their discussion in response 75.04 and based on operational interviews and comparison to a group of peers, Gannett Fleming views that the selected 30-R2 provides some recognition to the history of early retirements and trends towards the industry peer experience. The proposed 30 year life is not an indication of an early failure issue and instead represents an updating of the service life profile of the asset. The issue will be reviewed further as part of the next depreciation study update.

75.23. Is any of this experience related to physical life issues or is there some other factor driving the retirement experience?

Response:

Please see the response to CEC IR 1.75.22.

75.24. Are there specific locations or circumstances which are leading to these retirement experiences?

Response:

Please see the response to CEC IR 1.75.22.

75.25. Please provide some understanding as to why Terasen is experiencing a shorter 44 year life for mains.

Response:

Similar to Distribution Services, contributing to the noted increase from the current 2% annual depreciation rate to the 2.26% proposed is an increase of 0.37% for net salvage retirement costs. In recent years, these retirement costs reflected costs associated with the Low Pressure Main renewal project on the Lower Mainland and removal costs for mains relocation rework performed primarily at request of third parties (i.e. road infrastructure upgrades). It is the recovery of these retirement costs that have not been incorporated into existing depreciation rates.

Excluding the proposed 0.37% for net salvage, the adjusted recommended life depreciation rate becomes 1.89% which is comparable to the existing 2% depreciation rate. The recent depreciation study highlights there is no material difference in the expected average life of Distribution Mains compared to the average life estimate currently used.

75.26. Could the retirement experience be related to older steel pipe being removed and replaced with more durable polyethylene pipe?

Response:

Yes, an example of this type of replacement activity would be the CPCN Low Pressure Mains Renewal Project where older steel pipe was replaced with polyethylene pipe.

However, as indicated in the response to CEC IR 1.75.25, TGI's Distribution Mains have not observed to be experiencing a materially shorter life. Instead, a higher depreciation rate is required and proposed for the recovery of removal costs related to Distribution Mains work.

75.27. When third parties require Terasen to move a main from one location to another does this become a retirement of the old line and a replacement with a new line?

Response:

For plant asset tracking, the old line is treated as retired and the new line is considered a replacement.

75.28. Has Terasen done any investigation of the mains retirement experience to isolate and determine what may be causing the retirement experience?

Response:

For clarity, a primary contributor to the increase in the depreciation rate for Distribution Mains is the net salvage component which was discussed in TGI's response to CEC IR 1.75.25. In addition, as the proposed Life component of the depreciation rate is not materially different than what is currently in use, TGI has not conducted any investigation into possible causes of early retirement of Distribution Mains.

75.29. Has Terasen examined what it might be doing to extend the life of the plant in service and if so what is Terasen doing in that regard?

Response:

No, Terasen Gas has not undertaken any specific studies to determine means of extending the life of the assets. As indicated in the responses concerning early retirement (i.e. CEC IR 1.75.7, 1.75.10, etc.) of the assets listed in CEC IR 1.75.2, the proposed higher depreciation rates are not necessarily the result of shorter physical life but instead more due to the recognition of the need to provision for negative salvage and a catch-up for under-depreciation in the past. With more retirement data available, the Company is able to refine its depreciation rates to reflect the useful lives of its assets.

The recommended higher depreciation rates for the asset classes noted are consistent with those of other peer gas utilities and are not indicative of an asset management / early failure issue at Terasen Gas.

Attachment 5.1

BC Local Government Survey:

District Energy, Renewable Energy and Energy Planning

Report on Results

Prepared for: **Ministry of Energy, Mines and Petroleum Resources**

Prepared by: **Community Energy Association**
Peter Robinson, Community Energy Planner
probinson@communityenergy.bc.ca

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Community Energy Association

Connecting communities, energy and sustainability

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Disclaimer

The views expressed herein do not necessarily represent the views of the Ministry of Energy, Mines and Petroleum Resources, Ministry of Community Development, Ministry of Environment, BC Hydro, Pembina Institute, communities of Revelstoke or Quesnel, or FVB Inc.

About the Community Energy Association

The Community Energy Association is a charitable organization, assisting British Columbia local governments to promote energy efficiency and alternative energy through community energy planning and project implementation. We connect communities, energy and sustainability. The organization is an inter-agency collaboration; partners include the Province of British Columbia, Union of BC Municipalities, Planning Institute of BC, BC Hydro, BC Transmission Corporation, Terasen, Pacific Northern Gas, BC Transit, Translink, City of North Vancouver and District of North Vancouver. For information and many local government resources, please visit: www.communityenergy.bc.ca .

Contact:
Community Energy Association
Vancouver, BC
Tel: 604-628-7076
info@communityenergy.bc.ca
www.communityenergy.bc.ca

Executive Summary

Introduction

The Ministry of Energy, Mines and Petroleum Resources, Ministry of Community Development, Ministry of Environment, BC Hydro, Community Energy Association (CEA) and Pembina Institute, the communities of Revelstoke and Quesnel, as well as FVB Inc, initiated a survey of energy planning, efficiency, and renewable energy in BC local governments in November 2008.

Goals of the survey were to identify:

- **status** of various energy efficiency and renewable energy initiatives,
- **interest** in undertaking various actions,
- **barriers** to implementation of energy-related initiatives, and
- **support** that would be of most use.

The survey was distributed by email from Civicinfo to Chief Administrative Officers of all BC municipalities and regional districts, and from CEA to the CEA listserve (local government elected officials and staff) and to all CAEE (Community Action on Energy and Emissions) local governments. Results were collected November 6 - 20, 2008. The survey took about 45 minutes to complete; questions were lengthy, detailed and covering a broad array of energy/GHG topics. A previous survey, similar in content but much shorter, was conducted by CEA with UBCM and the Province in June 2006.

Survey Response Demographics

This results report is based on 49 completed surveys, representing 47 local governments (two municipalities submitted two responses). This is 25% of all BC local governments -- an excellent response rate for a survey of this length and complexity.

Survey responses are reasonably representative by government type, geographic location, and population. 19% of respondents were Regional Districts, and of the rest 43% had a population less than 10,000 and 39% a population greater than 10,000. However, responding local governments demonstrated somewhat more leadership than average, indicated by their higher than average CAEE participation and Charter signatories.

	Survey Responses	All BC Local Governments
CAEE participation	42%	28%
BC Climate Action Charter signatories	82%	~70%

Interpretation of Results

Local governments more favourable to climate action were more likely to respond to the survey (see the above chart), which indicates a slight skew to the results. Notwithstanding, the results can be extrapolated to show a reasonably good representation for all BC local governments. Survey results will help the Province and all survey partners better serve local governments through the most appropriate support.

Key Findings

The current status of local government activity is that generally, local governments are **doing the planning but not doing the doing yet**. Approximately half of respondents have energy / GHG plans underway and just under a third have completed them. Implementation and monitoring are still largely uncharted waters.

Top drivers for action on both energy and GHG indicated that the **BC Climate Action Charter is having a major effect** – the Charter is a top driver at both community-wide and operations levels. Playing a leadership role is another top driver across energy and GHG, at both community and operations levels. The strength of leadership as a driver could indicate that **the leadership shown by the Province of BC is contagious**, particularly as this is a new driver that has emerged since the 2006 survey. Leadership in operations is seen as important for supporting or stimulating community-wide action.

	Community -Wide Action	Local Government Operations
Top drivers for reducing GHG's	• **BC Climate Action Charter** (84%) • To play a **leadership** role (57%)	• **BC Climate Action Charter** (87%) • Playing a **leadership** role for community-wide efforts (74%) • Grant programs (38%)
Top drivers for reducing energy	• **Energy costs** (51%) • **BC Climate Action Charter** (49%) • To play a **leadership** role (49%)	• Playing a **leadership** role for community-wide efforts (66%) • **BC Climate Action Charter** (60%) • **Financial savings** (57%)

When analyzing barriers, the phrase "**the more things change, the more they stay the same**" seems appropriate. Top barriers are staff time and funding, identical to the top barriers identified in the 2006 survey. When asked about barriers to getting funding grants, staff time to write applications and lack of matching funding were top barriers. Unsurprisingly, a priority for support that local governments identified is direct assistance in obtaining funding.

Results indicate that a great deal more work in education and awareness is warranted. Local governments would benefit from greater knowledge of district energy; only 27% were very familiar with district energy and only 18% indicated they had developed sufficient understanding of the benefits and implications of district energy. In addition there appears to be a **thirst for more training** and education opportunities. Responses indicate that they want to learn more about all renewable energy technologies, particularly heat recovery, district energy, and heat pumps, with over 2/3 of respondents indicating interest in each. 90% would like education on energy utility ownership options, and 63% particularly wanted more information about local government ownership with private sector operation.

NGO's and consultants were identified as **the most useful sources** of district energy information. One reason for this response is that government contracts NGOs and consultants to deliver various outreach programs (e.g. CAEE). The finding is also reinforced by responses showing that CEA publications and services were useful.

The **next frontier** in local government climate and energy activity may be the shift from planning to implementation and the integration of climate and energy into economic development strategies. There is great opportunity over the next two years with establishing GHG targets in Official Community Plans by 2010, locking in planning and policies, and moving toward implementation.

Comparison of 2006 and 2008 Survey Results

Comparing the 2006 and 2008 survey results, we find differences, similarities and significant momentum as summarized in the table below.

Topic Area	Trend	2006	2008
Status of taking some steps toward developing a community energy/ GHG plan	↑	35%	55%.
Status of hiring an energy / GHG planner (either hired or planned)	↑	< 47%	66%
Primary drivers for energy / climate action	↑	Energy costs	Climate Action Charter, leadership, energy costs
Interest in district energy	↑	53%	86%
Barriers	→	Funding, staff time	Funding, staff time
Support priorities	↑	Funding assistance	Funding assistance and learning opportunities

Community Energy Association tools and support that local governments indicated in 2006 they would find useful, were confirmed in 2008 to have been useful.

Survey Highlights

Status of renewable and district energy

- Progress towards implementing district energy systems is slow but steady. 18% of respondents consider themselves to have completed the first phase of understanding district energy, but only 4% of respondents have operational district energy systems.
- About 50% of local governments have investigated the potential for small-scale renewable electricity generation to a degree and 87% indicated that they need support with feasibility assessment.

Status of bylaws and policies

Of 28 bylaws and policies listed in the survey, top ones **completed** are:

- Compact, mixed use development (completed by 34% of respondents)
- Policy on green building standards for new civic buildings (26%)
- Water conservation (24%)
- Green procurement policy for appliances and supplies in local government buildings (22%).

Top bylaws and polices **underway** are:

- Water conservation (underway by 59% of respondents)
- Land use & transportation coordination (54%)
- Energy/GHG in OCP or Regional Growth Strategy (53%)
- Transportation planning to encourage transit, cycling etc (51%).

Status of projects

Of 41 project types listed in the survey, top projects **completed** are:

- New civic buildings constructed to green building standards (completed by 11% of respondents)
- Waste reduction program (11%)
- Green appliances/products being procured (11%).

Top projects **underway** are:

- Energy retrofits of civic buildings, e.g. recreation centres, libraries (underway by 57% of respondents)
- Waste reduction program (56%)
- Promoting energy conservation through community outreach (39%)
- Actively promoting government- or utility-sponsored conservation and efficiency programs (38%).

Support Priorities

Local governments indicated they would be interested in the following support:

- 84% are very interested in education and training for staff and elected officials:
    - 65%-71% want to learn more about certain renewable energy technologies. In order of interest: heat recovery (e.g. wastewater treatment plant), district energy, ground/air/water source heat pumps, solar water/space heating;
    - 90% are interested in learning more about different options for ownership and operation of local energy utilities, with 63% interested in local government ownership with private sector operation.
- Expertise
    - Planning
        - 73% selected carbon neutral operations planning as a top choice for potential energy/GHG planning assistance;
        - 57% selected integrated water, waste and energy infrastructure planning as a top choice for potential energy/GHG planning assistance.
    - Funding
        - 55% selected direct assistance obtaining funding as a top preferred support for district energy advancement;
        - 51% selected a guide to funding, grants & support as a top preferred support for district energy advancement.
    - Technical
        - 51% selected technical expertise for planning/implementation processes as a top preferred support for district energy advancement;
        - 47% selected accessing/hiring/sharing energy planner/manager as a top preferred support for district energy advancement.
- Funding
    - 56% indicated that financing targeted at implementing district energy systems would be of value, while 38% said it might be.

Role of the Community Energy Association

Local governments are finding current CEA training opportunities and resource materials valuable. Respondents that used CEA services or publications (about half respondents), found the following particularly valuable:

- Training opportunities
    - CEA presentations (100% of respondents who received presentations found them very or somewhat helpful)
    - CEA workshops/conferences (92%)

- Resource materials
    - CEA website (100%)
    - CEA Funding Guide (96%)
    - CEA Renewable Energy Guide “Policy & Governance” (96%)
    - All other CEA Renewable Energy Guides (92%).

This information on high degree of local government satisfaction with these training opportunities may be useful in program design for further local government support and training.

Report on Results

Introduction

The Ministry of Energy, Mines and Petroleum Resources, Ministry of Community Development, Ministry of Environment, BC Hydro, Community Energy Association (CEA) and Pembina Institute, the communities of Revelstoke and Quesnel, as well as FVB Inc, initiated a survey of energy planning, efficiency, and renewable energy in BC local governments in November 2008.

Goals of the survey were to identify:

- **status** of various energy efficiency and renewable energy initiatives,
- **interest** in undertaking various actions,
- **barriers** to implementation of energy-related initiatives, and
- **support** that would be of most use.

The survey was web-based and distributed by email from Civicinfo to Chief Administrative Officers of all BC municipalities and regional districts, and from CEA to the CEA listserve (local government elected officials and staff) and to all CAEE (Community Action on Energy and Emissions) local governments. Respondents were given two weeks to complete the survey, with a reminder e-mail sent to CAEE communities and the CEA listserve after one week. Results were collected November 6 - 20, 2008. A paper version was available and used by several respondents. The survey took about 45 minutes to complete; questions were lengthy, detailed and covering a broad array of energy/GHG topics. A previous survey, similar in content but much shorter, was conducted by CEA with UBCM and the Province in June 2006. Trends between the two surveys are identified in this report.

Due to the small sample size, response rate, and lack of randomness (as demonstrated for example by the proportion of respondents who are members of CAEE) the results will be partially skewed. However it is expected that the results can be extrapolated to represent all local governments reasonably well.

The results of this survey will help the Province and its partners better serve local governments through the most appropriate support.

Survey Response Demographics

Complete survey responses were obtained from 47 local governments -- 25% of all BC local governments -- an excellent response rate for a survey of this length and complexity. Fifty-five responses were received, almost entirely by email, some by fax. Six surveys were extremely incomplete, and were therefore not included. This left 49 surveys, representing 47 local governments; two municipalities submitted two complete surveys each – and both were accepted allowing a more thorough representation of opinion within local government. The high response rate is an indication of the present level of interest and commitment of BC local governments to energy and climate action.

Survey responses are reasonably representative by government type, geographic location, and population. 19% of respondents were Regional Districts, and of the rest 43% had a population less than 10,000 and 39% a population greater than 10,000. However, responding local governments demonstrated somewhat more leadership than average, indicated by their higher than average CAEE participation and BC Climate Action Charter signatories. In terms of NRCan's nation-wide climate zones, where A is the mildest and D the coldest, 28 respondents were in climate zone A, 17 in B, 4 in C, and 0 in D.

	Survey Responses	All BC Local Governments
CAEE participation	42%	28%
BC Climate Action Charter signatories	82%	~70%

This survey report is based on completed surveys from the following communities. A few additional responses were received too late to be reflected in these results, though all responses were appreciated.

Northern BC
Peace River Regional District
Regional District of Fraser-Fort George
Dawson Creek
Fort St John
Hazelton
Queen Charlotte
Taylor
Williams Lake

Lower Mainland and Sunshine Coast
Fraser Valley Regional District
Metro Vancouver
Sunshine Coast Regional District
Abbotsford
Bowen Island
Coquitlam
Gibsons
Lions Bay
Mission
North Vancouver City
North Vancouver District
Squamish
Surrey
Vancouver
Whistler

Interior
Cariboo Regional District
Regional District of North Okanagan
Castlegar
Elkford
Kaslo
Peachland
Nelson
New Denver
Radium Hot Springs
Revelstoke
Sicamous
Vernon
Westside

Vancouver Island
Comox Valley Regional District
Regional District of Nanaimo
Campbell River
Colwood
Duncan
Islands Trust
Ladysmith
Langford
Saanich
Sayward
Tofino

Comparison of 2006 and 2008 Survey Results

	2006 Survey	**2008 Survey**
Number of responses	47 (including one local government that submitted two surveys)	49 (including two local governments that submitted two surveys)
Number of local governments that responded	46	47
Distribution of responses	Good in terms of: • Geographic location • Population • Type (municipality vs regional district) of local government	Good, as with the 2006 survey.
Primary driver(s) for energy planning	• Energy costs	Top 3 (all about same level): • BC Climate Action Charter • To play a leadership role • Energy costs
Percentage indicating they have taken some steps toward developing a community energy/GHG plan	35%	55%
Number of communities indicating they have complete energy / GHG plans	2%	6% in the last 2 years, 6% prior to that, and 53% have energy / GHG plans underway.

	2006 Survey	2008 Survey
Where activity at the time of the survey is being concentrated	• Water conservation • Wastewater reduction • Waste reduction • Cycling/pedestrian infrastructure	• Energy/GHG objectives in OCP or Regional Growth Strategy • Bylaws/policies for compact mixed-use development, land-use & transportation planning, development applications, water conservation, wastewater reduction & treatment, and waste reduction • Transportation planning to encourage public transit, cycling, etc. • Energy retrofits of civic buildings • Water conservation and wastewater reduction • Waste reduction • Efficient street lighting
Highest levels of interest	• Including energy objectives in OCP or bylaws/policies • Policies and education to encourage efficiency in buildings • Green procurement policies • Green fleets and alternative fuels • Solar heating and photovoltaics • Ground source heat pumps	• Land use & transportation planning • Building design • Infrastructure design • Local renewable energy production • Social marketing and community outreach • District energy system implementation
Interest in hiring an energy / GHG manager	LGs indicating this was an area of low interest, with 53% saying they had no interest in hiring an energy or GHG manager	• For Community Energy Planning, 33% of respondents already have at least one staff member tasked with energy / GHG reduction / air quality planning, and 38% are trying to get one • For Government Operations, 38% communities already have at least one staff member tasked with energy / GHG's, and 29% more are trying to get one

	2006 Survey	2008 Survey
Interest in district energy	LGs indicating this was an area of low interest, with 47% saying they had no interest in it.	• 35% indicated they were *very interested* in district energy • 51% indicated they were *somewhat interested* in district energy
Major barriers to energy planning and implementation	• Lack of funds • Lack of staff time	• Lack of funds • Lack of staff time
Highest priority indicated for tools and support (In the 2008 survey this question was asked with respect to district energy advancement only.)	• Funding guides • Funding related assistance	• Funding guides • Funding related assistance • Accessing, hiring or sharing an energy planner / manager • Access to technical expertise for planning and implementation processes

CEA tools and support	People said they ***would find*** the following useful:
	• A guide to energy-related funding
	• Assistance in securing funding
	• A guide on alternative energy technologies
	• A case study guide
	• On-the-ground assistance
	• Presentations to council
	• Staff training
	• Community workshops
	• Support in developing an energy/GHG baseline had the lowest level of support but was still indicated to be useful
		People ***have found*** the following CEA tools and support *very useful*:
		• Staff support
		• Presentations
		• Funding Guide
		• Renewable Energy Guide modules:
		  ○ policy and governance
		  ○ heating
		  ○ electricity
		  ○ utilities and financing
		• Workshops / conferences

Differences and similarities between 2006 and 2008 results:
The most significant differences between 2006 and 2008 results were:

- An increased number of primary drivers for energy planning. In 2006 energy costs was a clear driver, but by 2008 the BC Climate Action Charter and playing a leadership role, were as important, and GHG reduction had become a driver in itself.
- An increased percentage indicating they have taken steps toward developing a community energy/ GHG plan, from 35% to 55%.
- An apparently significantly increased level of activity, although this is hard to quantify.
- A very large increase in interest in hiring an energy / GHG planner. In 2006 53% specifically indicated they were not interested; in 2008 for both the whole community and local

government operations, about one third of local governments already have an energy/GHG planner, and another third are in the process of getting or trying to get one.
- With respect to district energy, in 2006 47% specifically said they had no interest in it, while in 2008, 35% said they were *very interested* and 51% *somewhat interested*.

The most significant similarities between 2006 and 2008 results were:
- The response rate and distribution.
- Major barriers to energy planning and implementation are the same – lack of funds, and lack of staff time.
- Highest priority tools and support indicated are still funding guides and funding related assistance. But accessing, hiring or sharing an energy planner / manager, and access to technical expertise for planning and implementation processes have both become priority.
- CEA tools & support that local governments indicated in 2006 they would find useful, were confirmed in 2008 to have been useful.

Background changes between 2006 and 2008:
The two surveys were set up differently, since the 2008 survey had more specific objectives (e.g. in regard to district energy and distributed electricity generation). The 2008 survey was considerably longer, and usually had more possible answers for selection. Some questions were worded considerably differently.

A number of major developments between 2006 and 2008 likely affected the survey results:
- The Province released its *Climate Action Plan*, *Energy Plan*, and *Energy Efficient Buildings Strategy*.
- To support these plans, the Province:
  - Mandated GHG targets in OCPs by 2010 and in RGSs by 2011.
  - Collaborated with the Union of BC Municipalities to develop the BC Climate Action Charter which commits signatory local governments to having carbon-neutral operations by 2012 and to building compact, mixed-use communities. At the time of the survey, over 130 local governments had signed the Charter.
- BC Hydro had begun its Sustainable Communities work.
- The CAEE program had expanded to involve 62 communities, and the program breadth had expanded from buildings to the full range of energy sustainability.
- CEA had launched its Funding Guide (*Funding your Community Energy and Climate Change Initiatives)* –distributed annually since 2006 through UBCM, and updated quarterly for current online downloads from the CEA website. CEA had also produced and distributed *Heating Our Communities,* and *Utilities and Financing* – two modules of a Renewable Energy Guide.
- CEA outreach to local governments over the past 2 years had increased substantially to the point where CEA is presenting at most major gatherings of local government elected officials or staff professionals in BC (20-30 presentations per year).

2008 Survey Results Analysis

Progress in Local Government Activity

Survey results indicate that steady progress is being made by local governments in tackling energy/GHG reductions at both the community and operations levels. Comparison of 2006 and 2008 local government energy survey results indicates that while 35% of respondents had some elements of an energy/GHG plan in place in 2006, this number has risen to 55% in 2008. A much higher level of interest was also demonstrated in 2008.

Energy / GHG Planning & Management – Community and Operations Levels

Top drivers for action on both energy and GHG (table below) indicate that the **BC Climate Action Charter is having a major effect** – the Charter is a top driver at both community-wide and operations levels. Playing a leadership role is another top driver across energy and GHG, at both community and operations levels. The strength of leadership as a driver could indicate that **the leadership shown by the Province of BC is contagious**, particularly as this is a new driver that has emerged since the 2006 survey. Leadership in operations is seen as important for supporting or stimulating community-wide action.

	Community-Wide Action	Local Government Operations
Top drivers for reducing GHG's	• **BC Climate Action Charter** (84%) • To play a **leadership** role (57%)	• **BC Climate Action Charter** (87%) • Playing a **leadership** role for community-wide efforts (74%) • Grant programs (38%)
Top drivers for reducing energy	• **Energy costs** (51%) • **BC Climate Action Charter** (49%) • To play a **leadership** role (49%)	• Playing a **leadership** role for community-wide efforts (66%) • **BC Climate Action Charter** (60%) • **Financial savings** (57%)

However as demonstrated below, motivation by itself is not sufficient.

Progress

Respondents show they are making steady progress at both the community and government operations levels, in developing energy/GHG inventories, engaging the community, and developing and implementing a plan. There are, however, many local governments that have not yet started many of the tasks – 31% to 83% depending on the task. There is no major difference between the status of progress in tackling either community-level or government operations.

Economic Development

When asked if their community economic development strategy gave consideration to energy supply and demand:

- 9% of respondents indicated *yes*
- 38% indicated *somewhat*
- 29% indicated that they were *not sure*
- 24% indicated *no*.

The majority of respondents (49%-55%) indicated that they were interested in incorporating either local renewable heating/cooling, small-scale power generation, district energy systems, or a community

energy utility, into their community's economic development strategy. 11-13% for each option indicated that they were not interested in this incorporation into the economic development strategy; these results may indicate a small but significant resistance to incorporating energy sustainability into community economic development strategies, or there may be other reasons for this lack of interest, which were not made apparent through the survey.

District Energy

Familiarity, interest and knowledge of opportunities

A high proportion of respondents are somewhat or very familiar with district energy:

- 27% of respondents considered themselves to be *very familiar*
- 59% *somewhat familiar*
- 14% *not familiar*.

Similarly, a high proportion are somewhat or very interested in district energy:

- 35% considered their local government to be *very interested*
- 51% *somewhat interested*
- 14% *not interested*.

In terms of conducting inventories of significant waste energy streams for district energy, the greatest headway has been made on landfill energy inventory where 27% have done this. The greatest areas of future progress are likely to be wastewater treatment plants and arenas where 19% intend to conduct waste energy inventories in future.

Results indicate that a great deal more work in education and awareness is warranted. Local governments would benefit from greater knowledge of district energy; only 18% indicated they had developed sufficient understanding of the benefits and implications of district energy. In addition there appears to be a **thirst for more training** and education opportunities. Responses indicate that they want to learn more about all renewable energy technologies, particularly heat recovery, district energy, and heat pumps, with over 2/3 of respondents indicating interest in each. 90% would like education on energy utility ownership options, and 63% particularly wanted more information about local government ownership with private sector operation.

NGO's and consultants were identified as **the most useful sources** of district energy information. One reason for this response is that government contracts NGOs and consultants to deliver various outreach programs (e.g. CAEE). (The finding is also reinforced by responses showing that CEA publications and services were useful.)

System implementation

Progress toward implementing district energy systems in communities is slow but steady. 18% of respondents consider themselves to have completed the phase of understanding district energy, with 41% of respondents having started that, and 41% still to start. Ultimately only 2 district energy systems are operational amongst respondents, representing 4% of respondents.

Bylaws

Only one local government respondent has implemented bylaws to encourage district energy implementation. 37% of respondents are interested in implementing such bylaws, and 61% said they might, while no respondents said they would not consider it.

Infrastructure work
35% of respondents said that there is infrastructure work scheduled in the near future that would facilitate district energy installation, 25% said they did not know, and 40% said that there is none.

Small-Scale Renewable Electricity Generation

Feasibility
Respondents estimated the level to which they had investigated opportunities for small-scale renewable electricity generation in their communities:

- 4% indicated that they had investigated *extensively*
- 48% indicated that they had investigated *some*
- 13% indicated that they *intend to*
- 35% indicated *none*.

87% indicated that they need support with feasibility assessments of small-scale renewable electricity generation systems.

These results indicate that although local governments are interested and making progress, some support with feasibility assessment would be beneficial (see below).

Consulting with more experienced communities
Asked if respondents had consulted with or toured communities that had implemented small-scale renewable electricity generation systems:

- 19% indicated *yes*
- 15% *intend to*
- 67% indicated *no.*

Selling power or local consumption
Respondents were asked if they would intend that power should be for local consumption, or if they would want to sell it to BC Hydro.

- 15% indicated *local consumption*
- 4% indicated *for sale to BC Hydro*
- 50% indicated *both*
- 31% did not know.

Existing small-scale renewable electricity generating systems in the community
19% of respondents indicated public electricity generation systems exist in their community, and 28% indicated private systems exist in their community.

Those who had indicated that they were aware of systems in their communities were asked about the public response and level of public consultation conducted beforehand. In 13% of installations there had been a negative public response, and in 21% of cases, it was considered that an insufficient level of public consultation had been conducted beforehand.

Status of Bylaws, Policies, Projects and Operations

Survey results generally indicate that local governments are making progress in the following areas:

- Land use and transportation bylaws and policies
  - 40-54% of respondents' local governments are underway with developing bylaws and policies in this area.
  - 6-34% have completed bylaws and policies.
- Water and wastewater
  - 59% of respondents indicated they were underway with water conservation in infrastructure bylaws and policies, and 24% indicated they had completed this.
  - 43% indicated they were underway with wastewater reduction and treatment in infrastructure bylaws and policies, and 11% indicated they had completed this.
  - 56% indicated they were underway with water conservation & wastewater reduction in infrastructure projects and operations, and 9% indicated they had completed this.
- Waste
  - 49% were underway with waste management bylaws and policies, while 17% had completed this.
  - 56% were underway with waste management projects and operations, while 11% had completed this.
- Community engagement on energy
  - 30-40% of respondents' local governments are underway with bylaws and policies on community engagement on energy, and 4-14% have completed them.
  - 38-39% are underway with projects on community engagement on energy.

Generally, communities are not making as good progress on:

- Infrastructure (except with water / wastewater and energy efficient streetlighting)
  - 7-36% are underway with bylaws and policies, while 0-9% have completed them.
  - 0-34% are underway with projects and operations, while 0-7% have completed them.
- Renewable energy
  - 13-20% are underway with bylaws and policies, while 0-2% have completed them.
  - 7-31% are underway with projects and operations, while 0-2% have completed them.

Renewable energy (electricity, heat, or cogeneration) stands out as being the area of least progress in both bylaws and policies, and projects and operations.

Interest and Knowledge

Respondents showed a high level of interest (generally 65-100%) in everything they were asked about relating to energy/GHGs. (This is likely reflective of the biased local government respondent sample; most respondents were signatories to the BC Climate Action Charter, and a high proportion are participants in the CAEE program.) Notable were:

- 85% of respondents were interested in, and somewhat familiar with, district energy. At the same time, from a list of methods of reducing energy demand (Question 8.1), interest in district energy systems scored lower than interest in land use and transportation, buildings and infrastructure.

- When respondents were asked to identify renewable energy technologies which they would like to learn more about, biomass and biogas scored lowest with just 49% and 45% of respondents selecting them respectively.

There may be some room for education on the benefits of district energy, biomass and biogas.

Local government knowledge appears to be lagging behind interest. For example:

- The majority of communities (63%) had not yet explored technologies to integrate existing excess energy streams into community district energy opportunities.
- The majority of communities (64%) had no staff expertise on green building rating schemes or energy performance standards for developments.
- Most respondents (81%) said their communities had not toured or consulted with communities that had implemented small-scale renewable electricity generation systems.
- Most respondents (87%) said they needed support with feasibility assessment for small-scale renewable electricity generation systems.

This gap between interest and knowledge indicates that local governments have some knowledge-building to do. This survey highlights specific knowledge areas sought by local governments, and preferred ways of receiving this support (see below).

Barriers

Internal and external barriers

Respondents were asked to rate internal and external local government barriers to advancing district or renewable energy systems in their communities. Internal and external barriers are those inside and outside the local government's operations; e.g. an internal barrier might be lack of staff time, and an external barrier might be insufficient influence over developers or an inability to find funding partners.

Internal barriers were overwhelmingly viewed as greater than external ones. The four greatest internal barriers were:

- Lack of funds
- Lack of time by staff
- Lack of comprehensive financial analysis
- Lack of knowledge/information on technology, by staff or council/board.

By a significant margin, and both selected by over 90% of respondents, the two biggest barriers were lack of funds and lack of staff time.

Barriers to obtaining funding

The two greatest barriers in obtaining funding, by a significant margin, were lack of staff time at over 75%, and lack of required share of matching funds at over 50%.

With lack of staff time as a major barrier, it will be a challenge for knowledge to quickly catch up with interest.

Future Support for Local Governments

Funding

Increased funding to local governments can mean both greater access to capital funds to implement projects, and more funds to enable staff to work in this area. Survey results on funding barriers (listed above), indicate that lack of staff time is the greatest barrier, and lack of the required share of matching funds is also significant. Greater project funding, e.g. an increased provision of grant funding, would undoubtedly help; but the greatest need indicated is for funds for staff time.

Preferred supports for district energy advancement

Respondents were asked to select their top supports for district energy advancement. The top four selected, by a considerable margin, were:

- Direct assistance obtaining funding
- Guide to funding, grants & support (which CEA has already produced – see below)
- Technical expertise for planning and implementation processes
- Accessing/hiring/sharing an energy planner/manager.

All of these could be met through provision of direct support to local governments (see below).

When asked whether financing specific for district energy implementation would be helpful, 56% of respondents indicated *yes*, 38% indicated *maybe*, and 7% said *no*; district energy financing could therefore be considered as part of future government support.

Direct support for local governments

Many gaps and barriers highlighted by this survey could be resolved by direct support for local governments. This could take the form of free, subsidized, or fee-for-service support (relative merits of these three approaches were not explored in this survey). It would be important for local governments to designate staff responsible for energy/GHG, for both community and operations levels.

There are several indications from the survey that direct support would be of benefit to local governments:

- Lack of funds and lack of staff time were indicated as the two greatest barriers -- the same top two barriers indicated in CEA's 2006 Local Government Energy Survey. Several respondents also indicated that they would like to know/implement more but did not have the time.
- Several respondents directly indicated they would like more one-on-one support, or access to experts.
- More respondents had used CEA's direct support activities (i.e. staff support (55%) and presentations (51%)), than any other CEA activities.
- There has been significant success in generating interest and motivation among local governments on energy and GHG emission reductions, but knowledge and understanding of opportunities lags behind. The majority of respondents (55%) indicated that no representatives of their local government had attended any training on the topics of district energy / small-scale renewable electricity generation.
- Several respondents indicated that their local government has very limited resources to conduct energy/GHG work. Several indicated they would like people to come in and do it for them at no cost, and/or that they need access to the technical expertise.
- Supports and assistance were indicated as required for district energy advancement (see above).

When respondents were asked for their top choices for potential energy/GHG planning assistance in the following categories, top selections were as follows:

Education

- workshops/conferences and training for elected officials and staff (requested by 84% of respondents)
- presentations to Council/Board (59%)
- site tours of completed projects in other communities (59%)

Community

- community energy / GHG planning (61%)
- district energy development (49%)
- renewable energy for heating (49%)
- small-scale renewable electricity generation projects (37%)

Operations

- carbon neutral operations planning (73%)
- integrated water, waste, and energy infrastructure (57%)
- acquiring carbon offsets (45%)
- building retrofits (43%)
- fleet energy efficiency (41%).

Regarding support in obtaining **funding**:

- 77% identified lack of staff time as a key barrier to obtaining funding
- 67% indicated lack of knowledge on funding as a barrier
- 55% indicated that direct help in obtaining funding, and
- over 50% indicated that a guide to funding and support would help them with district energy projects.

It is notable that CEA has produced a funding guide for local governments *Funding Your Community Energy and Climate Change Initiatives.* The guide was printed and distributed to all BC local governments in 2006 and 2007, and has been updated quarterly; current issues downloadable from the CEA website. Survey results would seem to indicate that additional support is required to promote this guide, to point to applicable funding programs, and potentially to assist with application-writing. This last point is indicated by 55% of respondents selecting *assistance in securing funding* as a key means to help them with district energy projects.

Community Energy Association (CEA)

CEA's support activities were accessed by about half the respondents. This could reflect a combination of CEA's limited resources, a need to better target and promote support activities, and a lack of time from local government staff (e.g. to read the guides). The following list ranks types of supports according to percentages of respondents that used them:

1. CEA staff support (55%)
2. CEA presentations, e.g. council meetings (51%)
3. CEA Funding Guide (47%)
4. CEA website (47%)

5. CEA workshops/conferences (45%)
6. CEA webinars (39%)
7. CEA Governments-and-Energy Listserve (31%)
8. CEA Renewable Energy Guide modules (27%)

Least familiarity was with CEA's Renewable Energy Guide modules, though of those familiar, 70% found them very useful. (nb: Two of the four modules were released just prior to the survey, and were not yet officially distributed, which would explain some unfamiliarity).

Local governments are finding current CEA training opportunities and resource materials valuable. Respondents that used CEA services or publications (about half respondents), found the following particularly valuable:

- Training opportunities
  - CEA presentations (100% of respondents who received presentations found them *very* or *somewhat helpful*)
  - CEA workshops/conferences (92%)
- Resource materials
  - CEA website (100%)
  - CEA Funding Guide (96%)
  - CEA Renewable Energy Guide "Policy & Governance" (96%)
  - All other CEA Renewable Energy Guides (92%).

This information on high degree of local government satisfaction with these training opportunities may be useful in program design for further local government support and training.

It is interesting that CEA's Renewable Energy Guides were the least utilized of CEA's activities but were among the most helpful, indicating that local governments are very interested in the level of detail that can be found in the Renewable Energy Guides but may not have been exposed to them or have made time to read them, lack of time being a top barrier for local governments. It takes considerably more time to read something and understand it for oneself compared to taking a training workshop, so funding to provide workshops & presentations on the guides (heating, power, utilities, policy and governance tools) may be an appropriate next step to build familiarity.

CEA presentations and workshops have a record (in this survey and otherwise) of being considered highly-valuable among local governments, and are among the most used means of support. Regional workshops building familiarity with CEA's Renewable Energy Guide (which deals extensively with district energy), would likely be an effective way to build local government knowledge. A webinar series would also likely be effective, and particularly cost-effective. It is noted that it would be helpful if the guides were updated, e.g. in 2-3 years. It is also noted that hard copies of the first two modules are no longer available; print funds would help create broader exposure.

The CEA website has proven to be an extremely cost-effective tool, with both high number of users and a high ranking of usefulness. It should be taken under consideration though, that although 100% of users considered it to be either *somewhat* or *very* useful, the majority of these (74%) considered it to be *somewhat* useful. This is unusually high out of the results for the CEA resources. This may either indicate that local governments do not find websites very useful, or that the CEA website in particular could be enhanced to make it more useful. Funding to improve the CEA website may be a cost effective use of resources.

Of CEA's publications, the Funding Guide is the most used, and it also has a high ranking of usefulness at 96% (52% very useful, 44% somewhat useful). To remain effective, this resource requires quarterly updates; with minimal funding this could be achieved, providing a highly cost-effective resource.

From CEA's experience local governments come to work on energy sustainability from different backgrounds, with different needs, and with different resources. Providing a range of options and services is the best way to ensure that they are able to fulfill their potential. For example smaller local governments have fewer resources and need greater hand-holding and education, while larger local governments can take the time to read detailed reports, understand, and act on them. A breadth of tools and resources needs to be maintained for their benefit.

CEA has traditionally provided free awareness-building support to local governments, and is increasingly challenged to fund this work. NGO's are increasingly funding their non-profit work through fee-for-service activities, which is a current option for CEA. Neither CEA nor this survey have explored willingness-to-pay for energy support. It is recommended, however, that a basic level of education support for local governments be funded; this will be much more cost-effective than a long series of one-offs with those local governments that are able to pay for service, and many will not choose to pay for basic information.

Finally, many survey comments focussed on the need for basic one-on-one or hand-holding service to local governments. For such support, it would be advantageous to have support staff situated in regions throughout the province, to better serve regional clusters of local governments. CEA is in the process of addressing this issue by engaging regionally-based representatives – currently situated in Victoria, Vancouver, Coquitlam, Kelowna, Trail, and Nelson. Expansion of this support network across the province would be advantageous to local governments.

Appendices

BC Local Government Survey – District Energy, Renewable Energy and Energy Planning

Results and Charts

Attachment 18.2

19. Exhibit B-1 – Tab1, Page 1 – Traditional Business Risk

Historically, the elements that made up TGI business risk were: the competitiveness of natural gas to alternative energy sources, namely electricity; the ability to attract customers and retain its customer base. These two elements influence the volume of natural gas (throughput) flowing through the TGI system. Ultimately throughput is the vehicle, from variable rates charged to customers, by which almost all of TGI's investments are recovered. All else equal, if throughput levels decline for whatever reason, TGI business risk increases.

19.1 What has Terasen done to mitigate the issues it has with regard to the competitiveness of natural gas to alternative energy sources?

Response:

The Terasen Utilities continue to be proactive in taking steps to improve the competitiveness of natural gas to alternative energy sources, including electricity. Competitive barriers can be financial and non-financial in nature, but ultimately they are barriers that impact the use of natural gas in homes and businesses in B.C., impacting the total throughput on the systems of the Terasen Utilities over time.

The Terasen Utilities consider key business issues that impact throughput on their systems as being:

- Provincial climate change and energy policies have increased the risk inherent to the Terasen Utilities core natural gas business;
- Natural gas' competitive position relative to electricity has been weakened;
- The Terasen Utilities are capturing a smaller percentage of new construction with natural gas service;
- Electricity is increasingly the choice for space and water heating in high-density housing;
- Alternative energy sources further weaken the Terasen Utilities competitive position with respect to natural gas distribution; and
- Fuel switching has also diminished demand for natural gas.

When evaluating the business risk of a gas distribution utility, it is the longer-term fundamental business risks that must be given primary consideration. If these risks reduce throughput, all else equal, rates will rise, further increasing business risk.

Other business issues as discussed in BCUC IR 1.40.1 and 1.40.2, also pose risks to the Terasen Utilities. However, in this Application the Terasen Utilities have focused on the business risks that have significantly changed since the last ROE hearing in 2005. The proactive steps the Terasen Utilities have taken to address these changes since 2005 are discussed below.

As stated in CEC IR 1.12.1, the Terasen Utilities have recognized the 6 business issues as independent factors because each item identified presents barriers and or obstacles that must be overcome individually for natural gas throughput volumes to stabilize or increase on the Terasen Utilities’ systems. Due to the fact that each factor presents its own challenges, by addressing and solving one factor, there is no guarantee that this will result in improved total throughput. Consequently, Terasen Utilities have taken a multifaceted approach to address the challenges presented by these business issues in hopes of reducing the risk these factors pose to the ability of the Terasen Utilities to recover their investment over the long term.

Below is a summary table of the risks factors relating to competitiveness that the Terasen Utilities have outlined in this Application and the Companies’ responses to those challenges. A further detailed discussion then follows on each issue. The Terasen Utilities have been proactive in bringing forth solutions to meet customers’ needs and to help lessen the business risks that are impacting the Companies’ business.

Business Risk Factors that Impact Throughput on Terasen Utilities' Systems	Challenges or Barriers to the natural gas business	Solutions to Reduce Business Risk	Actions Taken by the Terasen Utilities to Reduce Business Risk
1) Provincial climate change and energy policies have increased the risk inherent to core natural gas business	• Consumers look to reduce their use of fossil fuels in order to align with climate change objectives • Changing perception and behavior of consumers, particularly in B.C. as to the use of natural gas as an energy source • Encouraging reduction of GHGs, lowering energy consumption, and developing alternative (renewable) energy sources	1. <u>One climate system</u> • Examining GHGs on a regional basis rather than provincial 2. <u>Efficient use of existing energy</u> • Energy efficiency and conservation • Encouraging the right energy source for specific end uses. Using the "right energy form, for the right activity at the right time" 3. <u>Integrated energy grids</u> • Energy moves freely between jurisdictions therefore need to develop solutions that reflect this reality 4. <u>Development of alternative energy sources</u> • Natural gas is a foundational energy form that will supplement the use of other energy sources 5. <u>Price signals</u> 6. <u>Education</u> • Consistent messaging to customers about the right use of energy	• Meeting with Government ministries and other related agencies to promote Terasen's view on assumptions, solutions and path forward on how we reach these government goals and objectives o Participating in government committees and working groups. • The following reports have been used to communicate the solutions: o Smart Gas Strategies for BC o QUEST White Papers o Northwest Gas Association White Paper • Expanded EEC programs • Expanded natural gas service offerings (i.e. NGV, LNG and biogas) and integrated alternative energy solutions that are contained in recent TGI and TGVI Revenue Requirement Applications

Business Risk Factors that Impact Throughput on Terasen Utilities' Systems	Challenges or Barriers to the natural gas business	Solutions to Reduce Business Risk	Actions Taken by the Terasen Utilities to Reduce Business Risk
2) Natural gas competitive position relative to electricity	• Decline in price advantage of natural gas compared to electricity in B.C. • Differing nature of how natural gas and electricity costs are set into customer rates • Volatility of natural gas commodity as compared to electricity • Carbon tax applied to natural gas • Reduced consumption and throughput levels on the natural gas system • Changing perception of customers about how the use of natural gas contributes to climate change and GHG emissions	1. <u>Price Signals</u> • Customers should make decisions based upon proper price signals for both gas and electricity. • Natural gas to compete against the marginal cost of electricity	• Relatively flat delivery rates over the PBR Period (contained costs) • Managing Gas Costs: o Annual Contracting Plans and Price Risk Management Plans to help enhance the competitiveness of natural gas relative to electricity o Working with other utilities in the PNW through the Northwest Gas Association • Customer Choice Unbundling Program provided options for customers to lock into rates mitigating price volatility • Participation in the BC Hydro 2007 Rate Design to advocate for appropriate price signals • Participation in the BC Hydro 2008 LTAP to promote right use of fuel in right application • Lowering barriers to attaching customers to the natural gas grid o Main Extension (MX) Test Application • Expanded EEC programs

Business Risk Factors that Impact Throughput on Terasen Utilities' Systems	Challenges or Barriers to the natural gas business	Solutions to Reduce Business Risk	Actions Taken by the Terasen Utilities to Reduce Business Risk
3) TGI is capturing a smaller percentage of new construction 4) Electricity is increasingly the choice of high-density housing	• High upfront capital and installation costs for natural gas space heating as opposed to electric baseboards o Most developers select energy forms or solutions based on potential for increased margins when selling homes • Increasing demand for perceived "green" energy	1. Price Signals 2. Education • the right energy form for the right application at the right time and encourage end use gas applications • 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.	• New technologies • Lowering barriers to attaching customers to the natural gas grid o Main Extension Test Application o In Suite Piping Application o Thermal Metering Application
5) Alternative energy sources including electricity further weaken TGI's competitive position	• Policies focusing on GHG emission reductions and developing alternative (and renewable) energy sources • Changing perception and behavior of consumers on use of natural gas as an energy source • Increased demand for perceived "green" energy	1. Investment in alternative energy solutions, in conjunction with natural gas as a foundational energy form 2. Integrated energy grids 3. Price Signals 4. Education	• Expanded natural gas service offerings (i.e. NGV, LNG and biogas) and integrated alternative energy solutions as introduced in recent TGI and TGVI Revenue Requirement Applications

Business Risk Factors that Impact Throughput on Terasen Utilities' Systems	Challenges or Barriers to the natural gas business	Solutions to Reduce Business Risk	Actions Taken by the Terasen Utilities to Reduce Business Risk
6) Fuel switching has diminished demand for natural gas	• High volatility and fluctuations in commodity price of natural gas • Differing nature of how natural gas and electricity costs are set into customer rates • Industrial customers seeking the lowest cost energy and have over time switched to biomass, used oil, coal and other energy sources to reduce costs and increase margin.		• Price of commodity determines what energy form industrial/commercial customers will use if they have the ability to switch energy forms (i.e., Greenhouses)

Actions Taken by the Terasen Utilities to Reduce Business Risk

1. Provincial climate change and energy policies has increased the risk inherent to core natural gas business

The Terasen Utilities do not foresee and nor expect to get an accommodation from government(s) once GHG regulations becomes further defined and implemented. In fact we are supportive of the government energy objectives in reducing GHG emissions. Rather than asking government for policy accommodations, the Terasen Utilities have communicated their proposed solutions to government at all levels on how to arrive at the optimal balance for reducing GHG on a regional basis through efficient energy use and the production of energy with an efficient regional integrated perspective. The solution assumptions also include market pricing signals and consistent messaging to consumers of energy. Once common ground is found amongst government, business and other stakeholders related to these solution assumptions, the Terasen Utilities believe that appropriate policy will be put in place by government to achieve these goals. The Terasen Utilities have been actively seeking ways to reduce the business risks rising from provincial climate change and energy policies by proposing solutions to meet the objectives. The Terasen Utilities will continue this discussion with government and other stakeholders in hopes of reducing the business risks that are currently impacting are business.

The Terasen Utilities do not foresee a regulatory environment that exempts the GHG emissions that come from our customers' use of natural gas, given that 17% of BC GHG emission output comes from the consumption of natural gas. Thus, the cost to comply with the provincial GHG reductions targets and/or future regulations will be embedded into the cost to the consumer for using natural gas, just as the carbon tax does today. The future cost may take another form, such as a purchase cost to buy an offset to comply with the regulation or provincial GHG reduction target. This will have a direct impact on natural gas competitiveness to other energy alternatives in the long term, just as the carbon tax does today.

Since the announcement of the Energy Plan in 2007, the Terasen Utilities have continued to bring forth solutions for customers that help them manage their energy cost and support the energy and climate change goals of the government. These programs are discussed below.

a. Expanded Energy Efficiency and Conservation ("EEC") Programs

In 2008, the Terasen Utilities filed an application seeking to expand overall Energy Efficiency and Conservation ("EEC ") expenditures in response to the government policy developments. In addition to the province's 2007 Energy Plan, the *Utilities Commission Amendment Act,* 2008, (Bill 15) demonstrated government's ongoing commitment to energy efficiency and conservation. The new section 44.2 of the Act, pursuant to which the Terasen Utilities brought this Application, requires the Commission to consider "government's energy objectives" in determining whether to approve proposed demand side management expenditures. With this expanded EEC strategy, which was approved by the Commission, the Companies anticipate that EEC activity will continue to provide good value for customers in a manner that is consistent with government's energy objectives. In June 2009, TGI and TGVI both filed revenue requirements applications which seek to increase the spending for EEC in low income and rental housing, interruptible industrial applications and innovative technologies.

The Terasen Utilities have been involved in communicating the benefits of efficient use of natural gas to customers through seminars, trade shows, and other means of communication. The Companies have held seminars with architects, engineers and builders/developers ("AEDs") and have participated in trade shows to increase awareness of natural gas as a foundation energy form and efficient energy source for commercial and industrial customers. Moreover, the Terasen Utilities have educated their residential customers about the right use of natural gas as an energy source through bill communications, website, and brochures for tips.

b. Expanded Natural Gas Service Offerings and Alternative Energy Options in Recent Revenue Requirement Applications

In response to government policies for GHG reduction and development of alternative energy sources, as well as the changing perception of consumers on the use of natural gas an energy source, TGI and TGVI presented in their recent Revenue Requirement Application for 2010 and

2011, economic test and regulatory framework to support new alternative energy solutions, such as gas compression service for Natural Gas Vehicles, biogas upgrading, geothermal and district energy systems. These new service offerings will help customers to meet challenges and capture opportunities presented by a new focus on climate change and alternative energy sources. Bringing these solutions forward is the first step to help reduce the impact of government policies on existing natural gas customers, as it is likely to be a number of years before the benefit of these undertakings is materially realized.

c. Meeting with Government at All Levels

Since the 2007 Energy Plan was announced, the Terasen Utilities have met with government ministries to discuss and advocate solutions to climate change and energy related issues and policies. Particularly, the Terasen Utilities have a close association with BC's Ministry of Energy, Mines and Petroleum Resources ("MEMPR"), but have also met with the Ministry of Environment, Ministry of Transportation, Ministry of Education, Ministry of Agriculture and the Climate Action Secretariat and others.

In these meetings the Terasen Utilities have presented solutions to help meet the government objectives by developing a vision of using alternative energy sources, which will be supplemented by natural gas as a foundational energy form. These solutions and vision are discussed in various publications that Terasen Utilities have help developed in recent years:

- Smart Gas Strategies for BC - Canadian Gas Association working in conjunction with Terasen produced a report describing three approaches to improve the energy system, including use available energy efficiently, introduce alternative energy options, and move towards integrated community energy solutions (See Attachment 19.1 for a copy of A Vision for British Columbia's Energy Future: Smart Gas Strategies).

- QUEST White Papers – The Terasen Utilities participated in Quality Urban Energy Systems of Tomorrow ("QUEST"), which is a consortium of municipalities, provincial and federal governments, utilities and private industry, workshops in working together to promote an integrated approach for energy services in Canadian communities. To reach the federal government's 2020 target of reducing national emissions by 20% from 2006 levels, addressing energy use and emissions in urban areas and communities must be part of the solution. These two White Papers are a synthesis of the discussions and conclusions from the workshops in 2008 and 2009 (See Attachment 19.1 for a copy of QUEST White Paper I and QUEST White Paper II).

- Northwest Gas Association White Paper – explores the role of natural gas in addressing climate change, some practical steps consumers across the region can take to reduce their carbon emissions and the policy principles and initiatives to climate change (See Attachment 19.1 for a copy of Northwest Gas Association White Paper)

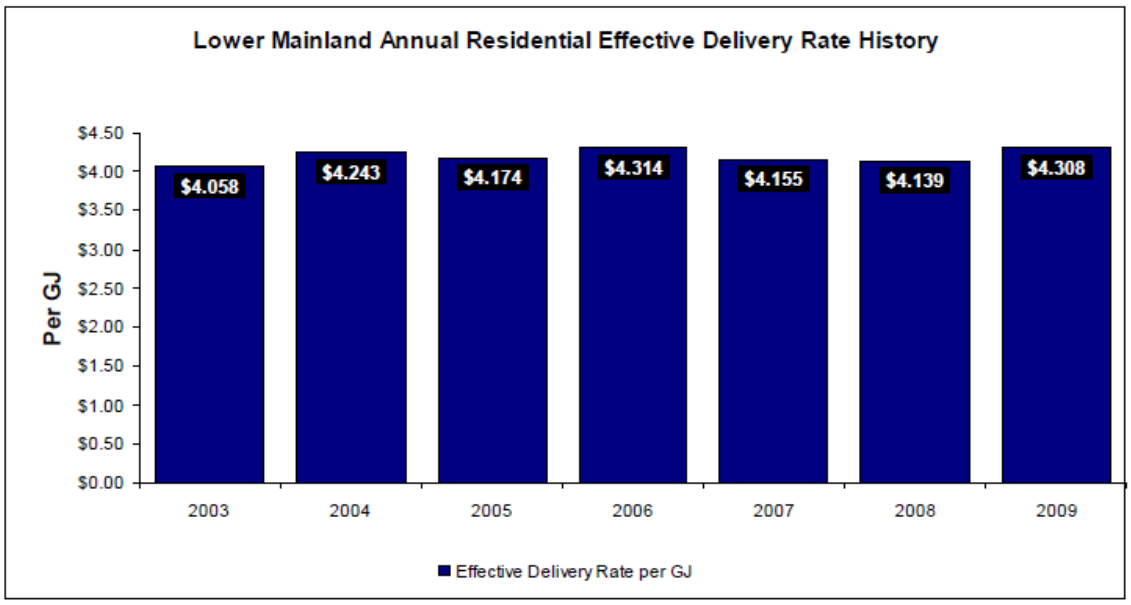
2. Natural gas’ competitive position relative to electricity have been weakened

Energy decisions and use are becoming more complicated for customers to understand. There are more barriers that impact the use of natural in homes and business in B.C. today than in the past, which impact the total throughput on the Terasen Utilities systems over time. Undertakings of the Terasen Utilities to help overcome these competitive barriers are discussed below.

a. Relatively Flat Delivery Rates over the PBR Period

TGI has operated under an evolving model of performance-based ratemaking (“PBR”) through settlements negotiated with customers and approved by the Commission, in which the Company has managed to keep delivery rates relatively flat over this time, despite throughput declining.

The following figure shows the effective delivery rate from 2003-2009 for Lower Mainland Residential customers and demonstrates the stability in delivery rates throughout the PBR Period. This similar pattern is also seen in other rate classes and service areas.



Assumes:
Natural gas use of 95 GJ
Terasen Gas effective rate includes basic charge and riders

b. Participation in the BC Hydro 2007 Rate Design

On March 15, 2007, BC Hydro filed its first general Rate Design Application ("RDA") since 1991 to update its rates and Terms and Conditions of Service. The Terasen Utilities' participation and position in this proceeding was mainly in the context that the BC Hydro RDA could do significantly more to promote achievement of the objectives included in the 2007 BC Energy Plan. In particular, the Terasen Utilities proposed there be initiatives or rate structures resulting in the avoidance of additional electric load, specifically, that load related to new space and water heating. The Terasen Utilities expressed their view that that electricity is not the "right energy form" for space and water heating.

c. Participation in BC Hydro 2008 Long Term Acquisition Plan ("LTAP")

On June 12, 2008, BC hydro filed the 2008 LTAP, a ten-year plan for acquiring demand-side and supply-side resources of electricity to meet demand in B.C. The Terasen Utilities' participation and position in this proceeding was mainly within the legislative and policy context, exemplified by "government's energy objectives" and the 2007 BC Energy Plan policy of "right energy form, for the right activity, at the right time". Within this context, the Terasen Utilities encouraged energy form switching and load avoidance consistent with that Provincial objective and promoted natural gas and alternative energy forms for space and water heating applications consistent with the 2007 BC Energy Plan.

d. Main Extension ("MX") Test Application

TGI and TGVI filed a System Extension and Customer Connection Policies Review Application in 2007. The Application was designed to ensure that the proper price signals were being sent to customers wishing to attach to the gas system. In addition the Application was designed to support the Companies' ability to promote the responsible use of natural gas as a method to achieve energy efficiency and optimal use of resources within the broader energy market. The changes requested send the appropriate market signals to developers and customers that are making decisions on using the energy form, for the right activity, at the right time. The changes requested, and approved by Commission, also offset some of the barriers deterring customers from connecting to natural gas. Consequently, the MX Test Review ensured that new customers were paying only fair share of costs to attach to the system.

e. Managing Gas Costs for Core Customers

Terasen Utilities continue to meet the objectives as defined in the Annual Contracting Plan and Price Risk Management Plan in providing reliable and cost effective gas supply for customers. Please see BCUC IR 1.40.2 and 1.88.1.1 for more details on these plans.

f. Customer Choice Unbundling Program

The Customer Choice Unbundling Program gives both residential and commercial customers the ability to manage their natural gas costs by purchasing gas at a fixed price in contracts ranging from 1-5 years.

3. TGI is capturing a smaller percentage of new construction while electricity is increasingly the choice of high density housing

Most developers select energy forms or solutions based on their ability to generate increased margins when selling properties. The high upfront capital and installation costs for natural gas space heating as opposed to electric baseboards have led to electricity becoming an increasingly choice of new construction, particularly of high density housing.

a. Sales Staff Working with Architects, Engineers and Builders/Developers

The Terasen Utilities have three regional sales teams focused primarily on maximizing natural gas use in residential new building construction. Our primary target is space and water heating, followed by lifestyle applications like fireplaces, cooking, barbeques, dryers, etc. The Terasen Utilities have primarily been focused on the multi-family market as this market constitutes the greatest percentage of new home starts in the region. The Companies' focus in this market begins at the planning stage with architects, engineers and builders/developers ("AEDs"). Generally through contacts in the industry, the companies are aware of plans prior to the building permit stage, and have an opportunity to influence energy choice.

Recently, the Companies have been successful in working with AEDs on hybrid solutions – combining gas requirements with renewable heat sources like geo-exchange and waste heat recovery. These hybrid solutions are perfect examples of how traditional gas utility service offerings must evolve to include alternative energy sources to optimize value for our customers, while minimizing the carbon footprint of the building. Hybrid solutions will form a fundamental service offering for the Terasen Utilities in this market now and into the future. The Companies sales staffs help developers determine the costs and the benefits energy usage in each individual project in the hope of determining the optimal energy solution for meeting both

economic thresholds but also energy efficiency and emissions reduction targets. Consequently, the Companies are seeing more and more developers moving towards a hybrid system that utilizes an alternative energy source married to traditional gas sources.

Additionally, the Terasen Utilities have been involved in lowering barriers to attaching customers to the natural gas grid through changes to the MX test and promoting a variety of technologies including in suite piping, and thermal metering, which are described below.

b. Wide Variety of Heating Technologies

The Terasen Utilities continue to investigate and encourage customers to use a variety of technologies for heating that can be both economical for the home/unit owner and beneficial to the developer, who pays for the initial capital installation. Some examples of these technologies include:

- High efficiency forced air furnaces, which are still the most common single family gas appliance;
- Residential boilers - provide heated supply return water to radiators or slab heating. These can be zoned but do not provide cooling. Cooling is traditionally from a separate appliance.
- Ground Source Heat Pumps can be married to a Rohbur Absorption heating/cooling unit. This is more common in European jurisdictions. However this is very costly but is starting to become more popular and costs are coming down.
- Combination Systems - Dual function hot water tanks provides heating hot water to a fan coil and hot air is then distributed through a forced air system and can provide both heating and cooling.
- Direct Vent Heaters – such as those manufactured by Bosche or Paloma. These heaters provide heated supply return water to radiators or slab heating.

c. In Suite Piping Application

TGI filed an Application for a change to the General Terms and Conditions of its Tariff in order to encourage the efficient use of natural gas in Vertical Subdivision developments in 2007. The Company proposed a new approach to providing Service (piping) to Premises (each individual suite) within Vertical Subdivisions, whereby the Company would install meters in the most appropriate location for the particular Vertical Subdivision, typically a meter closet, but continue the piping past the meter to the Premise. This approach would be undertaken in cases where the developer is not able to make space available to put the meter at the exterior wall of the individual Premises, but is able to make space available for a meter closet. In effect, TGI would install the Service Line to the Premises with the Meter Set part way along the Service Line.

d. Thermal Metering Application

TGI filed an Application in 2007 for Tariff Changes to allow for Thermal Metering, for a new program designed to encourage the efficient use of gas for space heating applications in Vertical Subdivision developments. Due to changes in the market place, in the Terasen Utilities’ view, there were more Vertical Subdivisions using electric baseboards rather than natural gas for heating purposes. In addition, the 2007 BC Energy Plan highlights a number of options and policy directions aimed at both encouraging efficient use of energy and ensuring that the right energy form is used for the right activity at the right time. It was the Company’s view that the introduction of thermal metering would address both the market conditions and the BC Energy Plan by providing a viable and affordable energy option for customers to use gas for space heating applications. While no customers are currently receiving this service, the Companies believe it is still important to have this option available.

4. Alternative energy sources further weaken TGI’s competitive position

The overwhelming attention to GHG emission reductions has changed customers’ perception of use of natural gas as an energy source and has increased demand for “green” energy and thereby development of alternative sources of energy. The Terasen Utilities, recognizing this need, have been involved in a number of initiatives in alternative energy solutions in conjunction with natural gas as a foundational energy form. These plans are descried in detail in both TGI and TGVI recent Revenue Requirements Applications that have been submitted to the BCUC.

Attachment 64.5

ATTRIBUTES OF DEFERRAL ACCOUNT AND GAS COST RATE SETTING METHODOLOGIES

Rate Stability

Rate stability refers to both the frequency and the size of rate changes. Customers would generally prefer rate changes to be smaller rather than larger and fewer rather than more, but these goals may conflict if there is a persistent upward or downward trend in gas costs.

Price Transparency

Price transparency refers to whether the gas cost recovery rates reflect market conditions and the overall accuracy of the price signal provided to customers. Setting rates annually generally provides a directionally correct price signal, but rate changes may be too infrequent to provide customers with a good idea of current gas price trends. Setting rates monthly or quarterly provides more frequent feedback, but may lead to oscillations that mask the underlying trend. It may be possible to reduce rate oscillation by setting rates based on the expected cost of gas over the next year rather than the expected cost in the next month or quarter.

Size of Deferral Account

In general, a mechanism that results in relatively small deferral account balances would be preferred to a mechanism that results in relatively large deferral account balances because large deferral accounts can mask underlying commodity price changes and alter the competitive position of the utility relative to smaller gas marketers. Large deferral accounts can also create issues related to the applicability of GCRA rate riders to new customers or customers switching to transportation service that might be avoidable or less important with smaller deferral account balances.

Efficiency of Process

Deferral account and gas cost recovery rate setting mechanisms that are relatively simple are preferred to those that are complex and difficult to understand, and adjustment mechanisms that involve less administration may be preferred to those that involve more administration. Annual review processes may tend to consume fewer resources than more frequent review processes unless the more frequent adjustments are accomplished mechanistically without the need for public input.

Attachment 72.2

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 75.3

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)