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February 10, 2011

British Columbia Utilities Commission
Sixth Floor
900 Howe Street
Vancouver, B.C.
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Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. ("Terasen Gas")
Application for Approval of a Service Agreement for Compressed Natural Gas ("CNG") Service and for Approval of General Terms and Conditions ("GT&Cs") for CNG and Liquified Natural Gas ("LNG") Service (the "Application")

Response to the British Columbia Utilities Commission ("BCUC" or the "Commission") Information Request ("IR") No. 2

On December 1, 2010, Terasen Gas filed the Application as referenced above. In accordance with Commission Order No. G-181-10 setting out the Regulatory Timetable for the review of the Application, Terasen Gas respectfully submits the attached response to BCUC IR No. 2.

If you have any questions or require further information related to this Application, please do not hesitate to contact Shawn Hill at (604) 592-7840.

Yours very truly,

TERASEN GAS INC.

Original signed:

Diane Roy

Attachment

cc (e-mail only): Registered Parties

1.0 CAPITAL COST ESTIMATE

Reference: Exhibit B-1, p. 50, Appendix B; Exhibit B-4, BCUC IR 11.3

1.1 Section 12B.5 Costs of the proposed General Terms and Conditions (GT&C) states that the forecast cost of service to be recovered from the customer will include the capital investment. Please confirm that the capital investment will be a cost estimate rather than the actual cost which Terasen Gas Inc. (TGI) will eventually request to be added to rate base.

Response:

Confirmed.

Terasen Gas is proposing that the NGV business be, to the extent practicable, run consistently with our other lines of utility business, where forecasts of the cost of service and volumes are used to determine appropriate rates for customer use without true-up. For example, presently when Terasen Gas contemplates adding a customer we employ a Main Extension ("MX") test[1], which takes the forecast volumes and forecast costs associated with adding an incremental customer and determines whether or not a Contribution in Aid of Construction ("CIAC") is required in order to make adding that incremental customer economically beneficial to all customers on the Terasen Gas delivery system. There is no true-up under the MX test that would allow TGI to recover additional funds from the new customers in the event that forecast volumes are not achieved (although customers may receive credit if volumes turn out to be higher than forecast), and construction cost variances are reviewed by the Commission in the normal course in a revenue requirements process. The costs of providing CNG or LNG service that are used in determining the CNG/LNG rate under the proposed Section 12B are forecasted in the same manner as for an MX test, the volume is predetermined by a "take or pay" provision required by Section 12B, and construction cost variances are capable of being reviewed in a future revenue requirements process in the normal course. Thus, while TGI customers bear cost risk under both the MX and cost of service test for CNG/LNG facilities, the latter reduces volume risk that is present in the case of main extensions.[2] In terms of the cost risk on CNG/LNG Service facilities, the Company also believes that, particularly since a significant majority of the costs of CNG/LNG service are fixed costs resulting from the capital equipment required to refuel NGVs, the forecast cost of service is likely to be reasonably accurate and any variances are best reviewed in the normal course in a revenue requirements process.

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[1] Order G-152-07 established the parameters of the MX Test which the Commission determined was in the public interest. Through annual compliance filings to the Commission, TGI has submitted that the Profitability Index levels as approved by Commission continue to be appropriate for the majority of main extensions."

[2] Incremental NGV customers requiring main extensions to bring service to a fueling facility will still be subject to the existing MX Test as well.

1.2 What will be the expected accuracy range (+/- percent) of the capital cost estimate? Will it meet the Advancement of Cost Estimating Class 3 level required for a Certificate of Public Convenience and Necessity (CPCN) application? If not, please explain why it should not be required to meet Class 3 standards.

Response:

Based on TGI's experience in the Waste Management project, the expected accuracy range is approximately +/- 10 percent of the capital cost estimate.

In regards to the Class 3 cost estimating level, the Commission decided in Order G-50-10 to require such degrees of accuracy for cost estimates in CPCN applications, but also recognized the potential for exceptions from this general requirement. TGI believes that cost effectiveness must be considered in applying the CPCN requirements. TGI is seeking approval for the related expenditures under section 44.2 of the UCA, and the amount of the expenditure is well below the CPCN threshold. The cost of acquiring such a degree of accuracy for expenditures well below the CPCN threshold would be inordinate to the cost of the amount being estimated. As such, Terasen Gas submits that it would be in the best interests of customers to avoid incurring the costs of performing an estimate to this level of accuracy.

1.3 How much contingency will be in the cost estimate? Assuming that TGI is seeking approval of a standardized model to calculate the rates under Compressed Natural Gas (CNG) and Liquified Natural Gas (LNG) Service agreements, should the cost estimate be required to include a standardized amount of contingency?

Response:

TGI's estimating practice involves using contingencies to account for costs that TGI expects to incur but where the amount is not known with precision and where the costs are not accounted for elsewhere. TGI will include a contingency in the cost estimate depending upon the conditions of each individual commercial negotiation. For example, the WM Agreement did not include a contingency, but used a P90 cost estimate.[3] TGI entered into fixed price agreements for the significant aspects of the fueling station, providing WM with a high degree of certainty. By contrast, the initial fueling station cost estimate for a potential LNG customer includes a 20%

[3] TGI interprets, with respect to this IR response, a P90 cost estimate as "90% confidence that the project will come in at or below the total estimated cost for the project". Cost information is based upon actual quotes provided by equipment suppliers and contract installers.

contingency. This project would involve a higher degree of complexity, longer construction period, and higher capital costs than the WM Agreement. TGI expects the decision on whether or not to include contingency in a cost estimate will depend upon the customer, the complexity of the project, and the product of commercial negotiations.

TGI believes it is important to avoid intentional cross-subsidization across rate classes through artificial inflation of the costs of service of one rate class over another through contingency funding. Contingency funds can be a valuable tool for ensuring the economical viability of a capital project in the event of potential cost overruns, particularly in projects with a high potential for cost overruns due to volatile supply prices or a lack of fixed price contracts. TGI believes that, given the cost and construction nature of the projects contemplated under the proposed NGV business model, the approach to use contingency funding when appropriate, is prudent.

1.4 Would 20 percent be a reasonable contingency? If not, what does TGI believe would be reasonable? Why?

Response:

Please see the response to BCUC IR 2.1.3.

The initial capital cost estimate for a potential LNG customer includes a 20% contingency; however, this may not be reasonable for all potential customers. The decision on whether or not to include a contingency and the contingency percentage will depend upon the nature of each underlying project.

1.5 As an alternative to including a standardized amount of contingency in the cost estimate that is used to calculate CNG and LNG Service rates, should the P90 cost estimate for the capital investment be used? What would be the pros and cons of this approach?

Response:

TGI believes that a P90 cost estimate can be an appropriate alternative to a standardized amount of contingency. A P90 cost estimate was used to calculate Waste Management's CNG service rate. TGI entered into fixed price agreements for the significant aspects of the fueling station, providing WM with a high degree of certainty. The main advantage of using a P90 cost

estimate is that it provides a high degree of certainty (90%) that the project will come in at or below the total estimated cost of the project.

Using a P90 cost estimate may extend the negotiation period of a service agreement with a potential customer, due to the time required to attain cost estimate data from manufacturers and contractors.

TGI expects the decision on whether or not to include P90 estimate or a contingency in its cost estimates will depend upon the customer, the complexity of the project, and the product of commercial negotiations.

1.6 TGI states that the estimated direct cost of the refueling station built for BC Transit in 1991 was $449,000 and that the actual cost was $787,000, an over-run of 75 percent. The Waste Management fueling station was estimated to cost a total of $737,944. What is the current estimate of total cost expected at completion of the facility? If this amount is different from the total amount that TGI intends to add to its rate base, please explain.

Response:

TGI will add the final cost of the Waste Management fueling station to rate base when the assets are available for use. Construction of the fuelling station at WM's premise is approximately 90% complete.

TGI contractors are also completing associated work on the project on WM's behalf while building the fueling station, under a separate agreement dated November 8, 2010. Margin generated from this related work is estimated at approximately $141,000, which provides a level of protection for Terasen customers from budget overruns on this project.

In 2011, the actual cost of service associated with the Waste Management fueling station will be offset by any recoveries received from Waste Management, including the margin generated from the separate agreement, and collected in a non rate base deferral account attracting AFUDC. This deferral account will be transferred to rate base effective January 1, 2012. TGI has proposed to recover or refund the balance of this account to TGI non-bypass customers over a three year period beginning January 1, 2012.

1.7 For the Waste Management of Canada Corporation (Waste Management) fueling station, please explain the reasons for all variances between the cost estimate and the expected cost to complete the project. How much contingency was in the cost estimate for this project?

Response:

As of the week of January 31st, 2011 the estimated total cost to complete is projected at $776,516, or 105% of the budget. Construction of the fuelling station at WM's premise is approximately 90% complete. The original cost estimate submitted in the Application was $737,944.

The variance of approximately $38,500 is a result of the following:

- Additional magnetic mapping of the work area to identify buried services and potential hazards.
- Elevation adjustments to the foundation pads for major equipment and re-work on the spool pieces.
- Two commercially rated protection posts in front of each filling location, as required by the British Columbia Safety Authority ("BCSA")
- Addition of individual grounding cables and a complete vent back system for all filling locations, as required by the BCSA.

In addition, TGI advanced the installation of filling posts originally planned for future facility expansion. The project plan was originally based around installation of filling posts for the first 20 trucks on the east side of the property. The area was located on a BC Hydro right of way underneath overhead electricity transmission lines. After initially approving this work plan, British Columbia Hydro and Power Authority subsequently expressed reservations and reviewed their earlier approvals. Given the uncertainty regarding their ultimate position, TGI decided to install additional filling posts in the area designated for future expansion of the facilities. This decision resulted in a cost increase of $79,400. This amount differs from an estimated $50,000 as described in BCUC Confidential IR 1.9.5. The $79,400 also includes additional protection posts as required by the BCSA and an inductive voltage survey. TGI will commit to seeking recovery of this cost in the negotiation for future fleet expansion.

As stated in its response to BCUC IR 2.1.6, TGI did not include a contingency in its cost estimate. Rather, the $113,000 generated from associated work performed for WM by TGI provided a level of protection for TGI customers from budget overruns on this project. This margin is roughly equivalent to a 15% contingency on the construction activities related to the fuelling service agreement.

1.8 Does TGI believe that customers will want CNG and LNG Service rates that are known with certainty when the Service agreement is entered into, before the fueling facility is constructed? If yes, please explain why. If no, please confirm that the Service rates should then be based on the actual cost of the fueling facility.

Response:

Based on discussions with customers interested in adopting NGV fleets,TGI believes that customers want CNG and LNG service rates that are known with certainty at the point the contracts are executed. This will necessarily precede the construction of the facility.

In general, the customers that TGI will be dealing with for NGV fueling stations will have no expertise or experience with the challenges associated with building an NGV fueling station. TGI has experience in this area and will generate more experience as additional stations are installed. Customers will look to TGI to provide expertise with respect to the design and construction of NGV fueling infrastructure. The proposed treatment of costs with respect to NGV station projects is consistent with current utility practices. For example, when customer contributions to main extensions are determined, the contributions are based on estimated costs for the main extension, as well as forecast demand. The new customers benefitting from the extension are not liable for additional costs in the event demand projections are not met.

In addition, fleets considering conversion to natural gas know that they can contract with fixed price certainty for the installation of diesel fueling facilities. As the incumbent service provides fixed price certainty, TGI believes that present and future customers will want price certainty and will expect NGV fueling infrastructure suppliers to offer price certainty to be competitive with the incumbent offering. In the absence of a competitive offering with respect to this element of the fueling service package, customers may elect not to switch to NGVs.

Finally, there is an important marketing issue with respect to selling the overall NGV package. TGI believes that if TGI were to attempt to sell fueling station services based on costs that are estimated and where the project risk of project overruns is solely borne by the NGV customer, NGV customers will perceive a lack of confidence with respect to the NGV stations and will be less likely to proceed with NGV service. This perception would slow down the adoption of NGVs.

1.9 Will the TGI shareholder assume any of the risk that a CNG or LNG fueling facility may cost more than forecast to construct or to operate and maintain? If yes, please explain in detail how this will be structured.

Response:

The shareholder and customers generally each assume part of the risk that a CNG or LNG fueling facility may cost more than forecast to construct or to operate and maintain. Customers obtain the benefit from costs being below budget, such that CNG or LNG rate revenues exceed the cost of providing that service. As in the case of any expenditure undertaken by the utility, the allocation of cost risk is as follows:

- prudently incurred costs of service are recoverable in rates; and
- the shareholder bears the risk that expenditures will be disallowed if they have been imprudently incurred.

Overruns on a project can occur for reasons that are beyond the control of the utility, and the prudence of costs related to matters within the control of the utility must always be assessed by reference to the facts available when the Company took the decision that resulted in the costs being incurred. TGI believes that this division of cost risk inherent in the statutory requirement for "just and reasonable rates" and the regulatory compact should be respected in the context of CNG and LNG service, just as it is in the context of other utility expenditures.

CNG and LNG projects backed by "take-or-pay" contracts that recover the forecast cost of service provide a significant benefit to customers by adding cost effective throughput to the system. TGI believes that having the utility invest in such projects to obtain the associated benefit makes sense from the customer's perspective and it is equitable for the customer to bear some risk, just as existing customers do any time service is extended to new customers. Please see page 64 of the Application (Exhibit B-1) for an explanation of why TGI believes that there will be a reasonable degree of cost certainty around the cost forecasts for CNG and LNG projects.

1.10 If the CNG or LNG customer requires rate certainty and the TGI shareholder is not willing to assume any cost risk, please confirm that other TGI ratepayers are then obliged to assume all cost risk under the proposed CNG and LNG Service arrangements. If no, please explain why not.

Response:

The shareholder and customers each assume part of the risk that a CNG or LNG fueling facility may cost more than forecast to construct or to operate and maintain, and customers obtain the benefit from costs being below budget. The allocation of cost risk, which is described in the response to BCUC IR 2.1.9, flows from the requirement for "just and reasonable" rates (defined in section 59(5) of the UCA) and principles of regulatory law (the regulatory compact), rather than a willingness on the part of TGI's shareholder to assume some cost risk as implied by the question.

CNG and LNG projects backed by "take-or-pay" contracts that recover the forecast cost of service provide a significant benefit to customers by adding cost effective throughput to the system. TGI believes that having the utility invest in such projects to obtain the associated benefit makes sense from the customer's perspective and it is equitable for the customer to bear some risk, just as existing customers do whenever service is extended to new customers. Please see p.64 of the Application (Exhibit B-1) for an explanation of why TGI believes that there will be a reasonable degree of cost certainty around the cost forecasts for CNG and LNG projects.

1.11 A party that desires cost certainty going forward must generally pay a premium to some other party to cover the risk of providing rate certainty. Examples would be the difference in interest rates between fixed and variable rate mortgages, and between fixed and variable priced gas purchases. Should the CNG or LNG Service customer who desires rate certainty pay a premium above the rate that is based on forecast costs? Why or why not?

Response:

TGI understands that the suggestion is to charge a predetermined premium over and above cost of service due to the contractual rate being based on forecast costs. For NGV stations, the bulk of the rate is determined at the time the station is built and it is composed of costs that can be estimated with a relatively high degree of certainty (capital costs and O&M costs). Terasen also has the ability to manage the cost of debt according to the businesses aggregate needs and the cost of equity is not expected to fluctuate widely as it is highly regulated. TGI believes, for the fairness and competitive considerations described in the response to BCUC IR 2.7.1, that the rate should be cost of service based, without charging a premium.

For greater clarity, TGI is not proposing to provide cost certainty with respect to the commodity delivered to the station. The cost certainty is only provided with respect to the fueling station

charge. A more appropriate example fitting this situation is a long term lease for a capital asset. In such a situation a customer can lock in cost certainty without paying a premium. Another example is the alternative case where a customer invests in a diesel fueling station. The customer can get fixed price quotes for equipment and installation services. If the customer decides to finance the purchase he can also lock in the cost of capital for the station.

As there is no fundamental cost driver justifying a premium, TGI believes that it is appropriate to fix the customers rate with respect to station assets. Basing the rate on forecasted costs does not really present a significant risk to TGI's existing customers that would require additional compensation over and above the benefit TGI customers receive from the additional throughput.

1.12 What does TGI believe would be a reasonable amount of rate premium for rate certainty in a 10 or 20 year agreement? Please explain how the amount was determined.

Response:

Terasen does not believe a rate premium for rate certainty is appropriate for the reasons outlines in BCUC IR 2.7.1.

2.0 PROFORMA TARIFF SUPPLEMENT

Reference: Exhibit B-1, Section 2.2, pp. 11-14

2.1 Please submit in standard Tariff Supplement form, a proforma Tariff Supplement for CNG Fueling Service and a proforma Tariff Supplement for LNG Fueling service incorporating the terms and conditions described in Section 2.2 of the Application.

Response:

TGI understands that the "proforma Tariff Supplement" being referred to would be a standard form contract that would be the template for future contracts signed by NGV customers. TGI has intentionally prepared GT&C with essential terms identified, without preparing a proforma service contract Tariff Supplement for advance approval. The Company believes that this is the most desirable approach in terms of advancing this line of business. The GT&Cs ensure the core terms of the agreements (such as the take-and-pay provision and the cost of service based rate) will remain consistent to ensure consistent and fair treatment of all customers and to minimize financial impact on ratepayers as a whole. The GT&Cs retain some flexibility for TGI to negotiate some of the other potential terms and conditions of service depending on the particular or unique nature of the customer's business and situation. A proforma Tariff Supplement, such as is currently in place for the Company's established and less complex service offerings, would limit the flexibility to meet specific customer requirements within the overall framework presented by the GT&Cs.

TGI has considered the approach outlined in BCUC IR 2.2.2 that contemplates including a list of potential trade-offs. As we are still developing business in this area, the Company believes that it will be very hard to anticipate "the trade-offs" or variables as each fueling station and each customer's need and circumstances will be different. Attempting to have a set of "trade-offs" prematurely could unnecessarily limit TGI's ability to meet the requirements of potential customers and secure their business. As the NGV business grows, TGI may be able to provide terms that may eliminate the need to negotiate the individual terms of each service agreement, but TGI believes that its proposed approach is the best approach at this stage. Ultimately, the Commission will be reviewing each agreement to ensure that the rate is just and reasonable.

2.2 To the extent that individual customers may desire different trade-offs in a service agreement, please discuss the possibility of providing a menu of proforma Tariff Supplements for customers to choose from rather than the proposed approach of negotiating unique agreements with each customer.

Response:

TGI understands that the "proforma Tariff Supplement" being referred to would be a standard form contract that would be the template for future contracts signed by NGV customers. TGI does not believe it would be practical at this time to provide a menu of pro-forma Tariff Supplements for customers to choose from.

NGV customers have varying fueling station requirements. The rates TGI has been developing for potential customer applications range from approximately $2/GJ to over $10/GJ. The wide range in rates reflects very different situations regarding the type of fueling infrastructure that is needed and the wide range in gas consumption.

In addition there are many items that need to be customized to a customer's individual situation. For example, a customer may have suitable electrical supply capability available at the site, or the customer might need the costs of adding electrical supply capacity added to the TGI scope of supply. Site security provisions and maintenance access provisions may also be different from site to site.

TGI had proposed in the last RRA a standard tariff for NGV service, which was more similar to the model contemplated in the question. Based on additional consultation with prospective customers, the Company has concluded that at this point in the development of NGV markets in BC, a more customized solution is needed, partially because we are not in a position to anticipate every customer's driving needs. As more experience is developed, TGI may determine that a more generic offering can service a significant segment of the market, but this approach is not optimal in the initial stages of market development for the NGV market.

3.0 COST OF SERVICE, ACCOUNTING TREAMENT AND RATE DESIGN

Reference: Exhibit B-1, Section 5.1, p. 55

"3. The proposed fueling charge is reasonable and relevant for CNG and LNG Service customers.

- Contract terms set to match the lifetime of the initial fleet of vehicles served by the station and the use of a predictable fuel charge achieves alignment with this principle."

3.1 Will the initial term of all contracts be 10 years? Please explain.

Response:

No, TGI expects that the initial term of future contracts will vary. TGI will, in general, attempt to maximize the term of the agreement to minimize the risk of stranded assets at the completion of the initial term. For most customers, we expect that the initial term of the contract will be matched with the expected lifetime of the NGVs that are being purchased for that facility. In most cases Terasen Gas anticipates this will be 5 to 10 years.

3.2 Could the customer select the term of the take-or-pay contract (perhaps within a range of 10 to 20 years) and therefore affect the rate under the service agreement? Why or why not?

Response:

TGI is submitting the response to this question confidentially under separate cover as it includes detailed discussion regarding TGI's proposed approach to commercial negotiations with potential NGV customers and it uses an example from the commercial negotiations that led to the execution of the WM agreement.

4.0 COST OF SERVICE, ACCOUNTING TREAMENT AND RATE DESIGN

Reference: Exhibit B-1, Section 5.1.1, p. 55

"The total costs to be used in the cost of service model include:

1. The capital investment, including any associated labour, material, capitalized overhead and other costs necessary to serve the Customer, less any contributions in aid of construction by the Customer or third parties, grants, tax credits or non-financial factors offsetting the full costs that are deemed to be acceptable by the British Columbia Utilities Commission;
2. Incremental operating and maintenance expenses necessary to serve the Customer;
3. Depreciation expense related to the capital assets associated with the contract;
4. Applicable property tax;
5. Calculated income tax expense; and
6. A return on rate base equal to the most recently approved rate (as approved by the British Columbia Utilities Commission)."

4.1 Please provide a table listing the inputs into the cost of service model.

Response:

The following table provides a summary of the inputs into the cost of service model:

Input Item	Parameter
In-service Date (ddmmyyyy)	
Minimum contract demand (GJ/year)	
Incremental O&M ($000's, per year)	
Capital Spending ($000s, per year)	
CNG/LNG Dispensing & Storage Equipment	
Foundation	
Pumps	
NG Dehydrator	
Contributions in Aid of Construction	
Capitalized Overhead Rate	14%
O&M Inflation Rate	2%

Input Item	Parameter	
Contract Term (yrs)		
Contract Rate Inflation (%)		
Depreciation Rates		
CNG/LNG Dispensing & Storage Equipment	5.0%	
Foundation	5.0%	
Pumps	10.0%	
NG Dehydrator	5.0%	
Capitalized Overhead	2.7%	
CCA Class		
CNG/LNG Dispensing & Storage Equipment	8	
Foundation	1.3	
Pumps	8	
NG Dehydrator	8	
Capitalized Overhead	51	
CCA Rate		
CNG/LNG Dispensing & Storage Equipment	20.0%	
Foundation	6.0%	
Pumps	20.0%	
NG Dehydrator	20.0%	
Capitalized Overhead	6.0%	
Income Tax Rate	25.0%	*
Property Tax Rate (Foundations)	3.91%	
Property Tax in Lieu of Rate	1%	
Return on Rate Base	7.93%	
AFUDC Rates & After Tax WACC	6.90%	**

*The income tax rate is 26.5% for 2011 only

**The AFUDC rate is 6.83% for 2011 only

4.1.1 How often will the inputs into the cost of service model be updated?

Response:

The inputs into the cost of service model are reviewed and updated each time that the model is used to evaluate an agreement and determine a contract rate.

5.0 COST OF SERVICE, ACCOUNTING TREAMENT AND RATE DESIGN

Reference: Exhibit B-1, Section 5.1.2, p. 55

"The cost of service model contemplated in the GT&Cs determines, on a contract by contract basis, the fueling charge that the customer will pay for the CNG or LNG Service."

5.1 Please confirm that TGI is seeking Commission approval of the cost of service model discussed in Section 5 of the Application.

Response:

It would be more accurate to say that TGI is seeking approval of the proposed GT&Cs, which incorporates the cost of service model described in Section 5 of the Application. In Section 5 of the Application, Terasen Gas is describing the accounting treatment and rate design required in order to support the proposed NGV business model. The GT&Cs employ the standard cost of service methodology that is widely accepted across the regulated utility industry and is consistent with the rate setting methods used for the Company's current offerings to customers. The only material difference between the cost of service proposals made in this application and those used for the Company's current offerings is the period over which the forecast cost of service is recovered via the forecast volumes. Terasen Gas believes that this difference is prudent for the NGV line of business due to the NGV customer preference for price certainty balanced with the core customer benefit from the increase use of our delivery system.

TGI has included a draft Final Order behind Tab G of the Application, which reflects that TGI is seeking approval of the GT&Cs.

5.2 Given that the accuracy of the proposed the cost of service model has not been determined, should a limit be placed on TGI's CNG and LNG investments? If not, why not?

Response:

No, a limit should not be placed on TGI's CNG and LNG investments. As long as any project has a positive contribution or impact that is beneficial to all ratepayers, it is in the interest of both ratepayers and the utility's investors to invest in the project(s). To set capital spending limits in advance, without regard to the benefits that a project or projects could generate would be against the interests of both groups. Terasen Gas has mitigated the greatest risk of the under recovery of costs through the contracts' structure and the degree of certainty of near term costs for compressor equipment. Furthermore, the CNG and LNG service year round load mitigates

some of the delivery rate pressure that existing customers may face in years to come as natural gas demand for heating declines. As discussed in Section 3.1.3.2 of the Application, the potential delivery rate benefits to existing customers are significant with a 15.2%, or $82.5 million, reduction in delivery rates by 2030.[4]

The Commission will be reviewing each contract as it is filed, and will be able to assess for itself in each case both the quality of the estimate and the likelihood that the ratepayer benefits from increased throughput will still exceed the amount of any potential overrun.

5.3 If the contract is not renewed after the initial term what are the customers' financial obligations to TGI? Will they be required to provide compensation to TGI for the present value of the revenue in the renewal period or for the book value of the CNG/LNG assets?

Response:

TGI is submitting the response to this question confidentially under separate cover as it includes detailed discussion regarding TGI's proposed approach to commercial negotiations with potential NGV customers and it uses an example from the commercial negotiations that led to the execution of the WM agreement. Public knowledge of TGI's approach to mitigating the risk of stranded assets will impair TGI's ability to negotiate such terms in future commercial agreements.

5.4 Is the cost of service model equivalent to the Economic Test in section 12.3 of the TGI GT&C?

Response:

The cost of service model and the Economic Test in section 12.3 of the TGI GT&C are similar in that they are both financial evaluations of the investment and use similar inputs; however, the cost of service model is different from the Economic Test in section 12.3 of the TGI GT&C in the following ways:

[4] Exhibit B-1; Reference Case Scenario, Section 3.1.3.2, page 25 and Appendix A-1, pages 31-41

- The Economic Test is a discounted cash flow analysis that uses average costs for a main extension and forecasted demand to determine if the revenue based on existing delivery rates from the proposed extension meets the test parameters; and

- The cost of service model uses the forecast cost of service and a known demand (the "take or pay" volume) to determine a contract rate specific to the investment contemplated- that is, the cost of service model determines the rate required to recover the forecast costs.

Both tests help to ensure that new customers and load can be added cost-effectively, so that existing customers are protected.

Please also see the response to BCUC IR 2.15.1.

6.0 FINANCIAL ANALYSIS

Reference: Commission Order G-143-99

When the TGI sold its natural gas vehicle (NGV) assets in 1999, only 49 percent of the net book value of the assets was recovered (net book value of NGV assets $4.1 million, proceeds from sale of the NGV assets $2.0 and a loss upon disposal of utility assets amounting to approximately $2.13 million).

6.1 Does TGI consider a 51 percent loss on the disposal of utility assets a significant stranded asset risk?

Response:

Terasen Gas believes that the 51% write-down of those assets experienced in 1999 was significant. However, the past experience is not indicative of the potential stranded asset risk of the proposed business model here. In contrast to the former business model, the NGV business model proposed in the Application achieves increased volumes and revenues for all customers on the Terasen Gas delivery system through the development of dedicated return-to-base refuelling assets structured into agreements with customers who will contractually be obligated to pay the forecast cost of service of these assets on a "take-or-pay" basis.

The prior model developed stand-alone refuelling assets which generated volumes and therefore revenues to support the Terasen Gas distribution system. They were sold out of the regulated utility for an amount below book value, and continue to provide volumes and therefore revenues to support the Terasen Gas distribution system to this day. Unfortunately, as shown in Figure 2-1 of Appendix A-2 of the Application, these volumes have declined substantially in recent years and will result in small increases to all delivery customers if the revenue cannot be generated elsewhere within the utility.

Terasen Gas believes that the proposed model, which ties assets and their resulting costs of service, to take-or-pay contracts with dedicated customers, is prudent and not comparable to the prior model in regards to stranded asset risk.

7.0 FINANCIAL ANALYSIS

Reference: Exhibit B -1, Section 2.2.2, p. 12

"The cost of service model generates a levelized 20 year rate that is then converted to an inclining rate structure over time. The rate of increase is fixed through negotiations with the customer and is set at a level that is intended to represent a general escalation factor. The intent is to generate a stable and predictable rate that increases but at a pace that is acceptable to the customer. In addition, the inclining rate reduces the early term rates making it easier for customers to adopt NGVs."

7.1 Given that levelized 20 year rate is based on forecast information, please discuss the risk of not recovering the cost of service due to differences between the actual and forecasts costs (inflation, cost of capital).

Response:

It is Terasen Gas' position that there is far greater potential (positive risk) that the agreements will be beneficial to all TGI customers and that the risk of not recovering the cost of service due to differences between the actual and forecast costs is minimal for several reasons:

- The significant costs associated with the agreements occur at the front end of the projects and are unlikely to vary significantly from forecast. In the case of the WM contract, TGI has received a fixed price contract for the CNG equipment which is the largest component of the capital costs. See also response to BCUC 2.1.3;

- Other cost of service items such as earned return, income taxes, property taxes and operating and maintenance expense are not expected to significantly vary that would detrimentally affect other customers' rates;

- Revenues are predetermined on a take-or-pay basis throughout the term of the contract;

- Revenue associated with volumes taken in excess of the minimum "take-or-pay" volume are captured in a deferral account and distributed to all TGI non-bypass customers in the following year, serving to offset cost variances that may occur; and

- Incremental volumes associated with the agreements increase the throughput on TGI's delivery system, which all else equal, increases revenue and reduces delivery rates for all TGI non-bypass customers. As demonstrated in the Reference Case Scenario in Appendix A-1 of the Application (item 4, pages 31-41), the increased throughput on the TGI's delivery system from the forecast volumes associated with CNG and LNG Service decreases the revenue requirement by approximately $2.3 million in 2015 and reduces delivery rates for TGI non-bypass customers by approximately 0.4%.

7.2 If actual costs are greater than forecast costs during the initial term of a contract, will TGI attempt to recover the additional costs when the contract is renewed?

Response:

No. In this scenario TGI would not attempt to recover from the CNG/LNG customer the additional costs attributable to the initial term of the contract when the contract is renewed. Regulatory principals generally prelude retroactive ratemaking, meaning that there is generally (i.e. absent another legitimate regulatory purpose for it) no ability for the Commission to approve higher rates upon renewal of the agreements for the sole purpose of collecting any under-recoveries from the initial term If, however, the under recovery was related to additional capital that was spent on the project, there would be an opportunity to adjust the rate going forward to reflect to the cost of service based on the un-depreciated capital remaining on the station assets at the time of renewal. In addition, if the ongoing O&M costs were higher than projected, there would be an opportunity to adjust the rate going forward.

7.3 Please provide the TGI delivery charge change by year for 1991-2010.

Response:

The annual inflation of the CNG and LNG service rate and annual changes in the TGI delivery rate are not directly comparable for several reasons:

- The annual TGI delivery rate change shown below includes the impact of variations in annual use (demand) and number of customers and changes to all aspects of the cost of service, including annual capital additions
- The CNG and LNG service rate is determined using a fixed customer over a fixed volume and is based on a single capital investment (minor capital additions occur throughout the period related to capitalized overhead)

The following table provides delivery charge changes by year for 1994-2010 for a Lower Mainland Rate Schedule 1 Residential customer, both including and excluding delivery rate riders. Information for 1991-1993 is not readily available.

TGI Effective Delivery Rate, Lower Mainland Residential Customer (Rate Schedule 1) 1994-2010				
	Excluding Delivery Rate Riders		Including Delivery Rate Riders	
Year	Effective Delivery Rate	% Change from Previous	Effective Delivery Rate	% Change from Previous
1994	2.408	0.0%	2.429	0.0%
1995	2.743	13.9%	2.743	12.9%
1996	2.890	5.4%	2.913	6.2%
1997	3.125	8.1%	3.105	6.6%
1998	3.182	1.8%	3.150	1.4%
1999	3.190	0.3%	3.260	3.5%
2000	3.295	3.3%	3.274	0.4%
2001	3.726	13.1%	3.505	7.1%
2002	3.765	1.0%	3.854	10.0%
2003	3.881	3.1%	4.058	5.3%
2004	4.048	4.3%	4.243	4.6%
2005	4.029	-0.5%	4.174	-1.6%
2006	4.201	4.3%	4.314	3.4%
2007	4.118	-2.0%	4.155	-3.7%
2008	4.189	1.7%	4.139	-0.4%
2009	4.470	6.7%	4.307	4.1%
2010	4.675	4.6%	4.645	7.8%

*Effective rate calculation assumes an annual consumption of 95 GJs per year

The impact of variations in annual use can have significant impacts on the delivery rate change in any given year. For example, if the impacts of changes in annual use were excluded, it would result in an average rate increase for the period 2004-2009 of 0.20% (compared to an actual average increase of 2.4%):

Approximate TGI Delivery Rate Increase (Decrease) When Use Rate Impacts are Excluded, %	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
	1.2%	-0.4%	2.0%	-2.2%	0.06%	0.51%

7.3.1 Please provide the TGI average delivery charge increase for 1991-2000 and 2001-2010. Also provide the fully functional electronic spread sheets for the calculations.

Response:

Please see the response to BCUC IR 2.7.3.

The delivery rate history for a Lower Mainland Rate Schedule 1 (Residential customer) has been used as the basis for the calculation. The average annual delivery charge increase for 1995-2000 is 5.5% and the average annual delivery charge increase for 2001-2010 is 3.6%. When delivery rate riders are included, the average annual delivery charge increase for 1995-2000 is 5.2% and the average annual delivery charge increase for 2001-2010 is 3.6%. As discussed in the response to BCUC IR 2.7.3, the annual delivery rate change includes changes in demand as well as changes in the cost of service and the decline in use rates has a significant impact on the change in the annual delivery rate experienced by all non-bypass customers. The annual throughput of the CNG and LNG service will serve to mitigate some of the delivery rate pressure that existing customers may face in years to come as natural gas demand for heating continues to decline. As noted in the response to BCUC IR 2.7.3, delivery rate information for 1991-1993 is not readily available.

Please refer to Attachment 7.3.1 for the fully functional spread sheet.

7.4 Please provide the TGI average weighted average cost of capital by year for 1991-2010.

Response:

The TGI after tax weighted average cost of capital (WACC) by year for 1994-2010 is shown below and is calculated as follows:

(Allowed ROE x Equity Proportion) + (Preferred Shares Rate of Return x Preferred Shares Proportion) + [(Long Term Debt Rate of Return x Long Term Debt Proportion) + (Short Term Debt Rate of Return x Short Term Debt Proportion)] x (1 – Tax Rate)

Year	After Tax WACC
1994	6.98%
1995	7.34%
1996	7.11%
1997	6.61%
1998	6.56%
1999	6.17%
2000	6.19%
2001	5.92%
2002	5.97%
2003	6.11%
2004	5.99%
2005	6.05%
2006	6.03%
2007	5.92%
2008	6.11%
2009	6.24%
2010	6.73%

Information for the years 1991-1993 is not readily available.

8.0 FINANCIAL ANALYSIS

Reference: Exhibit B -1, Section 2.2.2, pp. 12-14

"Customer Pays – The "take-or–pay" commitment provided by the customer ensures that the customer carries the bulk of the cost and risk associated with the investment. In the example presented above, the customer would be obligated to pay approximately $955,000 over the life of the service agreement. Of the initial $700,000, approximately $364,000 will have been recovered over the initial term strictly from the "take-or–pay" commitment."

8.1 Please provide the fully functional electronic spread sheets associated with the LNG fueling station example on pages 12-14.

Response:

Please refer to Attachment 8.1.

9.0 FINANCIAL ANALYSIS

Reference: Exhibit B -1, Section 2.2.2, p. 12

"After the initial term of the service agreement, the customer may renew the contract at an agreed-to rate with TGI. TGI will be negotiating terms, such as those negotiated with WM (discussed in Section 4) that minimize stranding risk for existing customers both during and at the end of the contract term."

9.1 Please discuss how TGI will determine the rate and terms for contracts to be renewed (economic test, take or pay commitment, early termination payment).

Response:

At the time when the contract is renewed, TGI will collect information from the customer and its own operations personnel regarding key Cost of Service ("COS") inputs such as:

Vehicle additions and volume projections;

- Term;
- O&M experience;
- Condition of station assets; and
- Costs associated with any required station upgrades.

A new COS will be developed based on these inputs and this will form the basis for determining the rate to be offered in the new agreement. The rate will be subject to the approved general terms and conditions at the time of renewal. For example, the new rate may be associated with a new take or pay commitment. The new rate agreement will be subject to Commission approval.

9.2 Please discuss the economic results of a contract being renewed for 10 years but terminated in the 5th year of the contract (removal costs, stranded asset).

Response:

What is provided for in the WM contract under section 9, items (b) and (c), and in several other contracts that Terasen has entered in with the approval of the BCUC, is the inclusion of a clause

requiring the customer to pay for the undepreciated plant costs (net book value of the assets) should the contract be terminated early plus the foregone future earnings. The net book value would include removal costs for assets that could not be removed and placed into service at a different location.

If the renewal agreement includes this provision, the write off of the stranded assets would be offset by the payment from the customer. Potentially TGI would be entitled to some value for the forgone future earnings that TGI would have expected to experience. As stated on page 65 of the Application, 50% to 70% of the plant costs are portable and can removed and relocated somewhere else. At the end of 15 years 75% of the asset value would have been depreciated and recovered in rates; leaving only about 25% of the asset cost not yet recovered. Of the 25% of unrecovered asset costs only 30% to 50% would be potentially stranded (7.5% to 12.5% of the original asset cost). Therefore, using the $700,000 LNG example provided on page 12 of the Application and assuming that the renewal agreement does not include an early termination clause, this would result in approximately $52,500 - $87,500 ($700,000 x 25% x 30% and $700,000 x 25% x 50%) in stranded assets.

9.3 Please confirm that when the initial term of Rate Schedule 22 and 22A Bypass Agreement Tariff Supplements expire, the customer can extend the agreement at a rate equal to the rate during the initial term.

Response:

Bypass customers can extend the agreement after the initial term.

The largest component of the bypass rate is a monthly facilities charge that remains fixed over the life of the agreement. There are also rates for monthly operating and maintenance charges and property taxes. These elements which typically make up only 20% of the total charge are typically adjusted annually to reflect changes in TGI's operating costs. A rate structure like the bypass rate structure could work for the capital component of the NGV rate because a monthly charge for capital is basically equivalent to a variable rate with a take or pay commitment. While the bypass rate structure could be used for the capital component, TGI favoured the proposed structure to the Bypass rate structure for two reasons:

1. TGI has made a conscious effort to provide a rate structure that is easily comparable to the costs a customer would incur for supply of a conventional fuel such as diesel. Discussions with potential customers indicated that a variable charge based on expected fuel consumption was a preferred approach for this market as it is more directly comparable to how other fuels are priced.

2. TGI also believes that the variable rate with a take or pay minimum is more appropriate because some cost items such as O&M are directly influenced by throughput. For example, compressor maintenance is influenced by throughput. The bypass model would only provide an inflation related adjustment to the O&M charge and this would not capture volume related O&M changes.

As such, TGI believes that the proposed rate structure is preferable.

10.0 FINANCIAL ANALYSIS

Reference: Exhibit B -1, Section 2.2.2, pp. 12-14

"An example of the output from the above discussed model is provided in Figure 2-1 below based on project costs for a proposed LNG fueling station (approximately $700,000 capital cost) for a fleet which consumes approximately 17,000 GJ per year."

10.1 Please revise the LNG fueling station to reflect actual capital costs exceeding forecasts capital costs by 20 percent. Provide fully functional electronic spread sheets showing the calculations.

Response:

Existing TGI customers continue to benefit in the situation where actual capital costs exceed forecast capital costs by 20 percent.

Using the example on pages 12 through 14 of the Application, a 20 percent increase in actual capital costs results in a revenue deficiency of $122,000, on a present value basis, over the ten year contract term. However, as demonstrated in the analysis below, this revenue deficiency is offset by the present value of the delivery margin benefit of approximately $467,000 associated with the incremental load on the TGI system.

Please refer to the table that follows, and Attachment 10.1 for the fully functional electronic spread sheets.

An increase of 20% in Actual Capital Costs Results in a Net Benefit to Existing TGI Customers

Line	Particulars	Reference	($000s)			
1	Actual Capital Costs and AFUDC	Line 2 x (1 + 20%)	854			
2	Forecast Capital Costs and AFUDC	BCUC IR 2.8.1, Attachment 8.1, Schedule 6, Line 35	712			
3	Capital Cost Variance	Line 1 - Line 2	142			
4						
5	Contract Revenue, contract term (present value)	BCUC IR 2.8.1, Attachment 8.1, Schedule 10, Line 24	667.4			
6	Actual Cost of Service, contract term (present value)	BCUC IR 2.10.1, Attachment 10.1, Schedule 10, Line 24	789.7			
7	Revenue Deficiency (present value)	Line 5 - Line 6	(122.3)			
8	Present Value of Incremental Delivery Margin Benefit	Line 26	466.8			
9	Net Benefit (Cost) to Existing Customers	Line 7 + Line 8	344.5			
10						
11	Determination of Present Value of Incremental Delivery Margin Benefit:					
12	Minimum Contract Demand (TJ)		17			
13	Rate 16 Volumetric Delivery Rate	Approved rate as at January 1, 2010	3.89			
14	Incremental Delivery Margin from Minimum Contract Demand	Line 12 x Line 13	66.1			
15			Year	Annual Benefit	Discount Rate	PV of Benefit
16			1	66.1	6.83%	61.9
17			2	66.1	6.90%	57.9
18			3	66.1	6.90%	54.1
19			4	66.1	6.90%	50.6
20			5	66.1	6.90%	47.4
21			6	66.1	6.90%	44.3
22			7	66.1	6.90%	41.5
23			8	66.1	6.90%	38.8
24			9	66.1	6.90%	36.3
25			10	66.1	6.90%	33.9
26						466.8

10.2 Please explain how the annual operating and maintenance costs for the LNG fueling station example were determined. If the costs were based on engineering estimates, provide the level of accuracy (P50, P90).

Response:

As described in the response to BCUC IR 1.10.1, the LNG model was designed to provide an illustrative example of the potential cost of service for a generic LNG customer. The capital costs, as well as annual operating and maintenance costs ("O&M"), are high-level estimates based on initial conversations with engineers. O&M costs are dependent upon the size, scope, and fuel consumption requirements of each individual project.

In this illustrative model, TGI assumed an O&M cost equivalent to 2% of the fueling system component with the annual O&M cost escalating at 2% per year over the term of the agreement. Subsequent conversations with the manufacturer indicate a range of 3 to 6% is more reasonable. When developing future cost of service models for actual customers, TGI will adjust its O&M estimates to reflect this.

10.3 Do the annual operating and maintenance costs for the LNG fueling station example include the cost of safety inspections, as well as preventative and routine maintenance as recommended by the manufacturer?

Response:

Yes, the annual operating and maintenance costs include the cost of safety inspections and preventative and routine maintenance as recommend by the manufacturer. The manufacturer's recommended maintenance schedule includes a wide range of periodic activities, from daily inspections for leaks and malfunctions to annual flow testing for plugging and obstructions. TGI intends to adhere to the recommended schedule in order to maintain a safe and reliable fueling station.

Please see TGI's response to BCUC IRs 2.10.2 and 2.10.4 for additional information.

10.4 For the LNG fueling station example, please provide a breakdown of the annual operating and maintenance costs by resource.

Response:

In the illustrative LNG fueling station example, TGI has assumed an annual O&M value equivalent to 2% of the fueling system major equipment t[5], or $8,000 per year. This is composed of:

- $3,000 per year in fees and administration costs, and
- $5,000 per year in contractor costs.

The annual O&M escalates at 2% per year, in each subsequent year of the agreement. Not included in this figure are:

- Approximately $12,000 per year in electricity costs required to operate the fueling station. This amount would be paid by the customer.
- Over $18,000 in spare parts for the unforeseen repairs and maintenance. This is included in the overall capital cost estimate of $700,000.

Additionally, the manufacturer's warranty covers the fueling system for one year of use, or 18 months from the date of shipment, whichever arrives first.

When developing a cost of service model for an actual customer, TGI intends to adjust its annual O&M estimate to a range of 3 – 6%, as suggested by the manufacturer.

10.5 Are system improvement costs included in the LNG fueling station example? If not, why not?

Response:

The capital cost estimate in the LNG example does not include costs for system improvement, which TGI considers to be any upgrades or future capital investments to expand or improve the fueling station. Such system improvement would trigger a renegotiation of the customer's fueling service charge. As an example, section 7(d) of the WM Agreement reflects this. Under

[5] In this example, the fueling system major equipment includes the LNG storage tanks, pumps and dispensers. This does not include site engineering, civil, mechanical and electrical field work. In this example the cost estimate of the major equipment is approximately $400,000.

section 7(d), the customer may request an expansion, and TGI, at its cost, would expand the fueling station to meet increased demand and to serve additional vehicles. However, TGI may then renegotiate the base price of the fueling station going forward. This type of provision mitigates risk to existing TGI customers because it creates a mechanism to recover any future capital costs through the contract rate as opposed to being embedded in future TGI delivery rates.

The LNG fueling station example does not contemplate upstream improvements such as liquefier expansion or additional plant storage. If required, system improvements of this nature will be addressed through a revenue requirement application or certificate of public convenience and necessity if applicable.

Terasen Gas does not anticipate any need for system improvements to the LNG delivery system up to the 1,040GJ/day cap limit under Rate Schedule 16.

11.0 FINANCIAL ANALYSIS

Reference: Exhibit B -1, Section 2.2.2, pp. 12-14

"The inclining rate structure provides a lower cost in the early years and a higher cost in the latter years for the customer contracting for the service. This difference can be significant depending upon the customer. The inclining rate structure is preferred as it helps encourage early adoption of NGVs."

11.1 TGI states that the inclining rate structure helps to encourage early adoption of NGVs. Will the higher cost in the latter years encourage customers to switch to other forms of energy?

Response:

The rate structure proposed provides a significant economic advantage compared to other energy forms at the outset of the agreement. The escalation proposed for the fueling station component of the rate is 2% per year. TGI believes that costs associated with other forms of energy, particularly diesel fuel, will also escalate over time. Hence the proposed escalating rate structure should continue to maintain the competitive advantage of NG over other forms of energy.

11.2 Does TGI have other rate classes that use a levelized rate, or a levelized rate converted into an inclining rate structure over the term of a customer's contract?

Response:

No, TGI does not have other rate classes that use a levelized rate, or a levelized rate converted into an inclining rate structure over the term of a customer's contract.

However, TGI understands that levelized rate structures have been used in other rate constructs such as those developed for district energy systems. For instance, such a rate structure was put in place for the South East False Creek district energy system. Other examples also include:

Dockside Green Energy LLP (in which Terasen Energy Services is a partner) is based on a customer class levelized rate which is lower in the early years of the project than the cost of service.

Corix's Multi-Utility Services is proposing lower customer rates than the cost of service for the Neighbourhood Utility Service at its UniverCity project in the early years of the proposed project.

Terasen Gas (Vancouver Island) (TGVI) had rate levels that did not meet the cost of service in the period 1995 to December 31, 2002. The revenue deficiency was accumulated in the Revenue Deficiency Deferral Account (RDDA). A Special Direction stated that beginning January 1, 2003, the Commission was to fix rates so that TGVI was able to recover its cost of service which included an RRDA balance of $87 million (Commission Order G-42-03 established those rates).

11.2.1 Should a premium be added to rate classes that use a levelized rate and provide customers with known delivery charges over the term of the contract? If not, why not?

Response:

Please see the response to BCUC IR 2.1.11.

12.0 FINANCIAL ANALYSIS

Reference: Exhibit B -1, Section 2.2.2, pp. 12-14

"Excess Throughput Rate – In the event the customer throughput exceeds projected volumes by more than 15%, there is potential for the customer to be overcharged for the fueling service. To reduce the potential for overcharging, the fueling service rate will be reduced to 25 - 50% of the base rate for all volumes in excess of 115% of the contracted volume commitment. This approach ensures that the potential to over-recover cost of service is limited."

12.1 Please revise the LNG fueling station example to reflect the customer's throughput exceeding projected volumes by 20 percent and the corresponding reduction in the fueling service rate. Provide fully functional electronic spread sheets showing the calculations.

Response:

In the LNG fueling station example the Excess Throughput Rate would be in the range of $1.28/GJ to $2.57/GJ. Actual volumes in excess of projected volumes by 20 percent would provide a revenue surplus in the range of approximately $12,000 to $14,000, which would be captured in the rate base deferral account and refunded to all non-bypass TGI customers in the following year.

Please refer to the table that follows and Attachment 12.1 for the fully functional electronic spread sheet.

LNG Fueling Station Example			
Actual Volumes in Excess of Projected Volumes by 20%			
Line	Particulars	Reference	
1	Base Rate ($/GJ)	BCUC IR 2.8.1, Attachment 8.1, Schedule 6, Line 35	$ 5.14
2	25% Excess Throughput Rate ($/GJ)	Line 1 x 25%	$ 1.28
3	50% Excess Throughput Rate ($/GJ)	Line 1 x 50%	$ 2.57
4			
5	Minimum Contract Demand (GJ/Yr)	BCUC IR 2.8.1, Attachment 8.1, Schedule 10, Line 30	17,000
6	Maximum volumes for Base Rate	115%	18,955
7			
8	Determination of Excess Volume		
9	Actual Volumes (GJ/Yr)	Line 5 x (1 + 20%)	20,400
10	Less: Minimum Contract Demand (GJ/Yr)	- Line 5	(17,000)
11	Excess Volume (GJ/Yr)	Line 9 + Line 10	3,400
12	Volume applicable to Base Rate	Line 6 - Line 5	1,955
13	Volume applicable to Excess Throughput Rate	Line 11 - Line 12	1,445
14			
15	Determination of Surplus Revenue		
16	*Scenario A- Surplus Revenue- 25% Excess Throughput Rate ($/GJ)*		
17	Base Rate surplus revenue	Line 12 x Line 1	10,039
18	Excess Throughput Rate surplus revenue	Line 13 x Line 2	1,855
19	Total Surplus Revenue	Line 17 + Line 18	11,895
20			
21	*Scenario B- Surplus Revenue- 50% Excess Throughput Rate ($/GJ)*		
22	Base Rate surplus revenue	Line 12 x Line 1	10,039
23	Excess Throughput Rate surplus revenue	Line 13 x Line 3	3,711
24	Total Surplus Revenue	Line 22 + Line 23	13,750

12.1.1 Will the "take or pay" commitment also apply to the increased throughput associated with the reduced fueling service rate? If not, why not?

Response:

No, excess throughput rates do not require take or pay commitments. The excess throughput rate only applies to the volume over and above the minimum take or pay commitment. The revenue received from the excess throughput rate is surplus revenue to the benefit of all TGI non-bypass customers to the extent that it exceeds the incremental O&M costs (e.g.

compressor maintenance) of providing that service. This is because the base rate has been set using the minimum take or pay commitment to recover the cost of providing the service to that customer.

13.0 FINANCIAL ANALYSIS

Reference: Exhibit B-1, Section 2.2.2, pp. 12-14; TGI 2010-2011 Revenue Requirements Application (RRA), BCUC IR 2.8.1

Table C-3-9: CS Test Parameters

Parameter Name	TGI 2009 MX Test Parameters	Proposed CS Test Parameters	Comments for CS Test Parameters
Application Fee - New	$85	Case-specific	Not applicable if gas service received through Rate Schedule 6. Applicable to all other rate schedules to measure volume through compression equipment.
Application Fee - Existing	$25	N/A	Not applicable.
Change of Service Frequency	5	N/A	Not applicable.
Overhead Rate	32.00%	Case-specific	Based on cost of compression equipment.
CCA Class 1	6.00%	20.00%	NGV compression and fueling equiment are Class 8.
Project Life	20	20	Same
Discount Rate	4.20%	4.20%	Same
Fixed SI	N/A	N/A	Same. Not applicable.
Variable SI	$0.16	N/A	Not applicable. Included in MX Test for other rate schedules (i.e. Rate Schedule 6).
Income Tax Rate	30.00%	30.00%	Same
Income Tax Surcharge	N/A	N/A	Same. Not applicable.
Property Tax Rate	1.85%	N/A	Not applicable. Compression equipment similar to station.
Working Capital Rate	0.50%	0.50%	Same
Demand Charge	Rate dependant	N/A	Not applicable.
Fixed O&M	Rate dependant	Case-specific	Based on the model/size of compression equipment
Variable O&M	N/A	N/A	Same. Not applicable.
In Lieu Rate	Rate dependant	N/A	Not applicable. NGV revenues are exempt from property tax.
Fixed Margin	Rate dependant	N/A	Not applicable.
Variable Charge	Rate dependant	5.00 $	Propose $5.00/GJ Compression Rate

(TGI 2010-2011 RRA, BCUC IR 2.8.1)

13.1 Please add a column to the Compression and Refueling Service (CS) Test Parameters to include the parameters used in the LNG example on page 12 -14 of the Application. If the parameters for the CNG projects are different from LNG projects also add a column for CNG parameters.

Response:

The parameters identified in the response to BCUC IR 2.8.1 in the TGI 2010-2011 Revenue Requirements Application reflected a twenty year discounted cash flow analysis. The financial evaluation of the CNG and LNG Service agreements are completed on a cost of service basis. Please refer to the response to BCUC IR 2.4.1 for a table of the inputs and parameters used in the cost of service analysis.

13.2 Please explain why TGI changed from the CS Test in TGI 2010-2011 RRA to cost of service economic test in the Application for evaluating CNG and LNG projects.

Response:

TGI's thinking evolved since the time the RRA was filed based on information we have learned from our additional efforts to pursue NGV initiatives during the RRA period. After exploring a variety of potential customer projects to determine budget level costs and rate estimates, TGI came to the conclusion that the significant variability of costs of providing fueling station service would complicate having a single postage stamp rate at this time. Please refer to the response to BCUC IR2 2.2 for more detail.

In addition, TGI has had the opportunity to gather more information regarding customer needs through specific project discussions with potential customers. These discussions have also led TGI to pursue the approach proposed in the Application. The market has also validated the customer specific approach as evidenced by the execution of the WM Agreement and negotiations that are progressing well on several other projects. TGI believes that customer specific solutions are what NGV customers desire at this time.

14.0 FINANCIAL ANALYSIS

Reference: TGI 2010-2011 RRA, BCUC IR 2.7.2

"For the most recent CNG station, the Kelowna School District ("KSD") expressed interest in natural gas as alternative to diesel for their school bus fleet, and then subsequently bought a natural gas powered bus.

...The current arrangement with KSD is that they are being charged for NGV service under Rate Schedule 6 with the requirement that a compression charge will be applied if TGI is granted approval in this proceeding to offer a compression and refueling service. This pilot will run until May 2010 at which point the project will be subjected to an economic test (CS Test) and, if it does not yield a PI of 1.0 or greater or the customer is not willing to agree to a Contribution in Aid of Installation, then the station will be moved to the TGI's FV site where it will replace the CNG package currently provided under contract by Clean Energy. TGI would then size and install the compressor for the KSD yard to meet the CS Test of 1 or above. If for some reason approval for compression is not received in this proceeding, TGI would apply for a tariff supplement to serve this customer so that it could begin to recover the cost from the KSD, i.e. the customer receiving the service on an ongoing basis."

14.1 Please provide the results of the economic test (CS Test). Include as schedule showing the forecast, actual and the differences between the forecast and actual costs, consumption and CS test parameters. Also explain any significant differences.

Response:

The situation with respect to the Kelowna School District (KSD) has changed. As of May 2010, the customer did not have sufficient NGV load at the station to pass the economic test contemplated in the TGI Revenue Requirement Application at a Compression and Dispensing rate of $5/GJ.

The situation with respect to TGI's Fraser Valley site has also changed. Effective September 30th, 2010 the service agreement with Clean Energy expired. Upon termination of the agreement TGI purchased the fueling station located at the Fraser Valley site on terms that were more attractive than the costs associated with relocating the KSD compression station to the TGI Fraser Valley site.

The approach with respect to development of rates for fueling station service has also changed. Rather than using the $5/GJ postage stamp rate and conducting the CS test, the business model is now based on developing a customer specific rate based on the volumes that the customer can commit to under a take or pay agreement.

In December of 2010, the KSD made a commitment to purchase an additional 11 school buses that will be delivered to their system in May of 2011. The addition of this incremental load will make the fueling station charge more economic for the customer. The estimated rate for this customer with the new load addition is approximately $10/GJ. This is higher than the pricing under the original model, but it still provides a net fuel price saving to the NGV customer. TGI is presently negotiating the terms of an agreement to provide fueling service to these vehicles. This agreement will be designed to recover the costs associated with the Pilot fueling installation as well as some additional system upgrades that are required to fuel the new vehicles. Upon completion of this negotiation, TGI will be submitting a contract to the Commission for approval to provide fueling station service to this customer on an on-going basis under the GT&Cs proposed in this Application.

The change in approach with respect to the KSD is illustrative of how the cost of service based business model is better suited for the early market development needs of the NGV business. Even with the addition of new incremental load provided by the new buses, this customer would not have been able to pass the CS test using a rate of $5/GJ for fueling service. As a result the new load could not be brought into service. The new approach will result in a higher rate, but one that is justified based on the costs of providing service and one that is still economically beneficial to the customer.

15.0 PROPOSED GT&C

Reference: Exhibit B-1, Appendix B - GT&C Section 12B; TGI GT&C, Section 12

15.1 Please explain why the proposed GT&C section 12B does not contain sections similar sections 12.3–12.4, 12.6–12.8 and 12.10 of the TGI GT&C.

Response:

The proposed GT&C Section 12B does not contain sections similar to Sections 12.3-12.4, 12.6-12.8 and 12.10 of the TGI GT&Cs because the proposed Section 12B only governs the CNG and LNG Fueling facility, which is addressed under a contract, such as the WM Agreement. The main extension test as described under Section 12 of TGI's GT&Cs would only apply in the event that a gas service connecting to the CNG or LNG Fueling facility is required to be installed.

An MX-type economic test akin to that specified in GT&C Section 12.3-12.5 is unnecessary for the CNG and LNG service itself under the proposed model because the cost-of-service based rate accomplishes the same purpose. The MX economic test is used to determine whether or not the forecast cost of service can be recovered based on forecasted consumption and a previously determined tariff rate. With respect to the proposed CNG and LNG services, by contrast, there is no forecast uncertainty in the consumption because the contract is "take or pay" and specifies a minimum contract demand. As a result, the GT&Cs employ a cost of service test to determine a cost of service based rate that recovers the forecast costs . Finally, there is no need to include provisions equivalent to GT&C Sections 12.6-12.8 (Contributions in Aid of Construction) because CIAC are already accounted for and excluded from the cost of service in the proposed cost of service model for CNG/LNG.

While the approaches used for main extensions and setting a rate for CNG/LNG Service are different, the effect is the same – both tests help to ensure that new customers and load can be added cost-effectively, so that existing customers are protected.

15.2 Please update the proposed GT&C section 12B to include sections similar to sections 12.3–12.4, 12.6–12.8 and 12.10 of the current TGI GT&C.

Response:

Please refer to the response to BCUC IR 2.15.1.

16.0 PROPOSED GT&C

Reference: Exhibit B-1, Appendix B - GT&C Section 12B; TGI GT&C, Section 12

16.1 Please provide an example of a CNG or LNG customer required to pay a contribution in aid of construction (CIAC). Provide fully functional electronic spread sheets showing the calculations.

Response:

The rate that is determined for CNG or LNG service is unique to each customer and therefore, unlike main extension tests, there is no circumstance where a customer will be required to pay a contribution. This is because the CNG or LNG service rate charged to a customer is not a predetermined value; rather, the derived contractual rate recovers the cost of service experienced over the contract term associated with providing the incremental CNG or LNG equipment and operating costs to that specific customer. In the main extension test the current delivery charge rates and Basic Charges are an input value along with the forecast incremental volumes and number of new customers to determine if the incremental margin revenue is sufficient to cover the incremental cost of service for that main extension. If there is a deficiency such that the PI index is less than 0.8, a CIAC is required for an individual main extension. In setting the rate for CNG and LNG Service any incremental delivery margin prior to the point of compression service is not included (i.e. credited to the compression cost of service). The incremental throughput on the TGI delivery system and delivery rate impacts to all TGI non-bypass customers are considered when a CNG or LNG Service agreement is evaluated. Potentially, if a customer wants to have a lower CNG or LNG service contract rate they could, as part of the contract negotiation, provide a contribution to offset the upfront capital costs to provide the service. Alternatively, a contribution could be received from a third party, such as a federal or provincial government branch, to support the development and promotion of natural gas as a vehicle fuel to lower GHG. In such a case the third party funding would be credited against the capital costs in determining the customer's rate.

An example of having a contribution in aid of construction is provided in Attachment 16.1. In this example, the capital cost of $750,000 is offset by a contribution in aid of construction of $44,000, which results in an initial rate of $5.001/GJ. This rate would be escalated by 2% each year of the 10 year agreement and then set at the unit cost of service rate per GJ for each of the following 10 years.

16.2 Please provide an example of how a CIAC refund would be paid to CNG or LNG customer. Provide fully functional electronic spread sheets showing the calculations.

Response:

The proposed General Terms and Conditions Section 12B does not provide for refundable contributions in aid of construction (Customers' Advances for Construction). In the event that the agreement is terminated, the net book value of the Contribution in Aid of Construction would be credited against the net book value of the CNG or LNG gas plant costs to determine the price the assets would be sold for to the customer. In the event of TGI removing the assets there may be a net credit which would be paid to the customer. A spread sheet is not required for the response to this question.

17.0 LNG SERVICE FOR VEHICLES

Reference: Exhibit B-1, Section 2.3.2, pp. 16-18

17.1 Please describe the significant differences between operating a LNG fueling station and operating a CNG fueling station.

Response:

LNG and CNG fueling stations are both designed to be very similar in operation to stations that deliver conventional fuel such as gasoline or diesel. For both LNG and CNG the dispensing process would include the following steps:

- Connect the filling hose – note this also grounds the vehicles as both CNG and LNG dispensing hoses are conductive;
- Initiate the fill;
- Wait until the vehicle has filled and the system has automatically shut down; and
- Disconnect the filling hose from the vehicle.

For CNG filling, no personal protective equipment is required. For LNG filling the person operating the dispenser must wear gloves and long sleeve clothing to protect against the cold temperature of the fuel and the operator must also wear a face shield to protect against potential splash back when the filling hose is disconnected from the vehicle.

Requirements for periodic inspection of the equipment are similar. At a minimum, monthly inspections of the equipment as well as approved preventative maintenance program visits are required.

Basic inspections are comparable for a LNG and CNG Stations. Elements checked include mechanical pumps, alarm panels, emergency shut own systems and control systems. Specific equipment used in each system varies, but the safety and preventative maintenance systems used are very comparable. From a safety perspective CNG requires respect for the high pressure of the fueling system and for LNG systems respect for the cold temperature of the fuel is paramount.

An additional difference in operations between CNG and LNG stations is the means by which the commodity is delivered to the station. For CNG stations, the natural gas is delivered to the station via pipeline using TGI's existing pipeline infrastructure. For LNG, the commodity is delivered to the station via tank truck.

17.2 What qualifications are required and necessary to safely and legally operate a CNG Fueling facility?

Response:

In order to legally operate a CNG facility a company requires the following:

- BC Safety Authority Contractors license;
- Employee with a BCSA high pressure Special Purpose license to construct, operate and maintain compressed natural gas station equipment;
- BC Safety Authority operating permit, obtained upon final commissioning inspection; and
- Registration of pressure vessels with the Boiler Branch.

Terasen Gas has the contractor license and has properly certified staff in place to operate this type of station. The construction permit for the project will turn into an operating permit after commissioning. Registration of pressure vessels is one of the responsibilities of the project manager in building the station.

17.3 What qualifications are required and necessary to safely and legally operate a LNG fueling station?

Response:

In order to legally operate a LNG facility a company requires the following:

- BC Safety Authority Contractors license;
- Employee with a BCSA liquefied natural gas Special Purpose license to construct, operate and maintain LNG station equipment;
- BC Safety Authority operating permit, obtained upon final commissioning inspection; and
- Registration of LNG vessels with the Oil and Gas commission above a specified tank size by application.

Terasen Gas has the contractor license and properly certified staff in place to operate this type of station. The construction permit for the project will turn into an operating permit after commissioning. Registration of LNG vessels is a task that is executed by the project manager when the station is built.

17.4 How do the risks and safety requirements differ between a CNG fueling station and a LNG storage and fueling facility?

Response:

While there may be a perception that LNG and CNG have substantially different risks and safety requirements, TGI's experience is that the risks and safety requirements have much in common because CNG and LNG are different forms of the same fuel. TGI will apply the same base safety management program for a CNG station to an LNG station. The LNG station will however have the following additional factors to consider:

- LNG is un-odorized. The liquefaction process removes the odorant so it is not possible to manually detect leaks. LNG systems are designed with automated methane detection systems to mitigate this risk.
- As LNG is a cryogenic fuel, special training is required for refueling staff, where CNG is self serve with no training requirement.
- Refueling staff require gloves and protective eye wear as protection from the cold temperature of the fuel.
- Water or an ABC rated fire extinguisher can be used on a CNG fire. Use of water will make a LNG fire larger by increasing the liquid boil-off rate. Purple K fire extinguishers should be on hand for LNG fires. Additional training of safety personnel and first responders is required to ensure that the proper methods of fire fighting are deployed in the event of an incident.
- Depending on the quantity of LNG stored, dispersion plume modeling may be required as part of the hazard and operability assessment for an LNG facility.

TGI has experience operating LNG assets since 1971 and has developed appropriate programs to manage the risks and safety requirements for handling and distributing LNG.

17.5 Please provide details regarding additional safeguards, insurance requirements, limitations on liabilities and indemnifications that TGI envisions would be required in a typical LNG Fueling Service Agreement over and above those that would be in a typical CNG Fueling Service agreement.

Response:

There are no requirements internally or externally to provide additional insurance, limitations on liabilities or indemnifications for LNG stations over CNG Stations. LNG requires transport of fuel from the LNG plant to the customer site and the standard company coverage limits are in place. LNG transport is not a new function for the company and as such no new coverage will be required for this operation.

17.6 Please describe the codes and standards that are applicable for the use of LNG as transportation fuel. Is the current state of codes and standards development adequate to support the use of LNG for transportation applications in British Columbia?

Response:

The following is a list of the US and Canadian Codes utilized for the design, construction, operation and maintenance of LNG Stations:

- NFPA 57 – LNG Vehicular Fuel Systems Code – 2002 (this is now rolled into NFPA 52);
- NFPA 59A – Standard for the Production, Storage and Handling of Liquified Natural Gas;
- NFPA 52 – Natural Gas Vehicular Fuel Systems; and
- CSA Z276 LNG Production, Storage and Handling (This standard is under development and does not deal with dispensing. For dispensing we reference NFPA 52).

Canada is working on its own stakeholder developed code but this code is not yet available. Terasen Gas is a member of this code development group and to this point nothing in the draft is in conflict with any of the codes listed. The BC, Toronto and Quebec Safety Authorities recognize the above list of codes and all Canadian LNG projects under development refer to this list.

18.0 LNG STORAGE FACILITY DESIGN CONSIDERATIONS

Reference: Exhibit B-1, Section 2.3.2

18.1 What size and capacity of LNG storage facilities at potential customer locations does TGI consider likely?

Response:

LNG storage facilities at customer sites will be sized according to the specific usage projections for that customer. LNG is a fuel which needs to be kept cold in order to remain in the liquid state. If LNG is kept in storage for extended periods, a portion of the fuel will convert to gaseous form and pressure will build up in the storage tank. If left too long in storage, losses will occur through tank venting. (Tanks are engineered so that this can occur in a safe manner; however for economic reasons this practice should be minimized.)

To eliminate the need to vent, it is desirable to size the customer's storage facility so that fuel is resupplied on a regular basis (e.g. 7 to 10 days). The resupply process introduces new cold fuel which converts vapour back to liquid form reducing tank pressure.

A large customer (e.g. 50 trucks using 150,000 GJ/ year) will typically require a 15,000 USG storage facility. Resupply is done using a 10,000 USG LNG tank truck. 15,000 USG is the most common size of storage facility used in the North American market.

Smaller customers (e.g. 10 trucks using 15,000 GJ/year) may elect to use a small system such as the IMC 6000, storage and dispensing system offered by Chart Industries. This system has a storage tank of approximately 5,500 USG. Resupply to these units would require part load deliveries using the same 10,000 USG LNG tank truck.

18.2 What, if any, would be the limiting design factors associated with such LNG storage facilities from a technical perspective?

Response:

TGI's Fueling Station LNG storage facilities will be designed to meet the following requirements:

- NFPA 57 – LNG Vehicular Fuel Systems Code – 2002 (this is now included within NFPA 52);
- NFPA 59A – Standard for the Production, Storage and Handling of Liquefied Natural Gas; and

- NFPA 52 – Natural Gas Vehicular Fuel Systems.

Information regarding the NFPA codes can be viewed at the following link:
http://www.nfpa.org/aboutthecodes/AboutTheCodes.asp?DocNum=57&cookie%5Ftest=1

In addition, the LNG stations we will be building will meet the requirements being developed in CSA Z276 LNG Production, Storage and Handling can be viewed at the following link:
http://www.neb-one.gc.ca/clf-nsi/rthnb/lnk/lqfdntrlgs/lngsftywrkshpa5-eng.pdf

These specifications set out a variety of requirements governing design, testing, site layout and construction of LNG stations including such matters as acceptable materials of construction, secondary containment requirements and setbacks from property lines.

18.3 What, if any, would be the design factors associated with such LNG storage facilities arising from the LNG supply requirements.

Response:

Please refer to the response to BCUC IR 2.18.1

19.0 LNG SUPPLY–RATE SCHEDULE 16

Reference: Exhibit B-1, Section 2.3.2, pp. 17-18; Appendix C – Rate Schedule 16

19.1 TGI notes that LNG for the LNG Fueling Service could be supplied under Rate Schedule 16 – Interruptible Liquified Natural Gas Sales. Clause 3.2 of Rate Schedule 16 notes that "Terasen Gas reserves the right to curtail Dispensing of LNG should it determine it does not have the capacity to supply the Customer's request." Please describe the terms and conditions that would apply to LNG Fueling Service given this restriction. What impact would the interruptible nature of Rate Schedule 16 have on the ability to negotiate a firm "take or pay" quantity?

Response:

In the event that the customer was prevented from purchasing LNG under Rate Schedule 16 due to interruption of Rate Schedule 16 service, the customer would be given temporary relief from the take or pay commitment in the fueling station service agreement for the duration of the supply interruption to the extent that the interruption prevented them from achieving their take or pay commitment in the fueling station service agreement.

The fact that Rate Schedule 16 is an interruptible service is an impediment to growing the LNG for Transportation business as the nearest alternative for LNG supply is in Portland Oregon (Northwest natural Gas peak shaving facility).

Customers are concerned about the potential limitation in supply, but recognize that actual supply interruptions have been very limited and may be mitigated to a limited extent by the customer's on-site supply of LNG in the fueling facility.

Looking forward, TGI anticipates that additional investment in LNG storage for the transportation market may be required to achieve the growth targets specified in the LNG Application in Section 3.1.3.1. Such additional investment in LNG assets would need to be justified by the additional revenue generated through LNG sales. TGI plans to make the case for such incremental investment once sufficient demand for Rate Schedule 16 sales has been demonstrated and the business has grown to the point where the 1,040 supply limitation associated with Rate Schedule 16 has become a limiting factor to the growth of the business.

19.2 Please confirm that an interruption in or a lack of LNG supply due to restrictions under Rate Schedule 16, or any other supply arrangements the customer has established, would not relieve the customer from its "take or pay" obligations under the LNG Service agreement.

Response:

As discussed under BCUC IR 2.19.1, the interruption of supply under Rate Schedule 16 would relieve the customer temporarily of their take or pay obligations. This would be pro-rated relief for the durations of the interruption. TGI believes it is unreasonable to enforce a take or pay obligation where TGI is the source of supply and TGI has interrupted service.

19.3 Rate Schedule 16 limits the total quantity of LNG available for sale in aggregate to all Rate Schedule 16 customers to a total Available LNG Capacity of 1040 GJ per day with each individual Rate Schedule 16 customer limited to 50 percent of the total Available LNG Capacity. Please describe the practical limitations that this may impose on TGI's ability to develop the LNG Service, in terms of the numbers of fueling stations, size of fueling stations and the number of NGVs.

Response:

Rate Schedule 16 has a limit of 1040 GJ/day (379,600 GJ/year) of supply capability imposed during the five year pilot period. To date no customers have taken service under Rate Schedule 16 so the full 1040 GJ/day is available. This limit does not reflect supply capability but is a regulatory limit set to ensure that the supply of LNG to Transportation markets does not impose any unintended or unanticipated problems on the Tilbury facility and its role as a peak shaving and backup supply resource.

As shown in Appendix A1 in Table 3.1 (p 13) a heavy duty truck consumes approximately 2,500 GJ/year of LNG. Thus, the supply limitation under Rate Schedule 16 would allow Terasen Gas to supply approximately 152 heavy duty vehicles in total before making an application to increase the amount of supply permitted. Project discussions to date have identified opportunities that range from 9 vehicles to 50 vehicles per fleet. Assuming a fueling station sized to serve an average of 25 trucks per fleet, the supply limit would allow TGI to bring on 6 LNG fueling station projects using 62,500 GJ/year each.

Achieving this level of market development will demonstrate the need for continuation of service and will form part of the justification for a transition from a pilot program to a permanent tariff.

19.4 Describe the impact that the Terasen Gas (Vancouver Island) Inc. (TGVI) Mount Hayes facility will have on TGI's ability to supply LNG for the LNG Service once

the Mount Hayes facility comes into service. Include an analysis of the annual and monthly volumes available, the service requirements on the TGVI system and the means by which LNG would be transported to the LNG Fueling Facility in the TGI Service Area. If the transportation includes transportation by BC Ferries, please describe the requirements, regulations or restrictions that might apply to LNG tanker trailers, including those specifically associated with the transportation of dangerous goods.

Response:

The addition of the Mt. Hayes LNG facility on Vancouver Island provides additional flexibility with respect to LNG operations by adding a second peak shaving and backup supply resource to the combined TGI and TGVI system.

The Tilbury facility has storage capacity of 600 MMscf or approximately 656,000 GJ of LNG (conversion factor 0.9145). The Mt. Hayes facility has a storage capacity of 1,500 MMscf or approximately 1,640,000 GJ of LNG. Liquefaction capacity at Tilbury, after recent upgrades, is 5.4MMscfd and the liquefaction capacity at Mt. Hayes is 7.5 MMscfd. The addition of Mt Hayes has increased LNG storage capacity in the system by 250% and production capacity by 140%. TGI believes that the addition of a second LNG facility is a factor that should be considered in determining the appropriate cap for LNG shipments to transportation markets and that the completion of the Mt. Hayes facility may warrant an increase to the 1040 GJ/day limit discussed in the response to BCUC IR2 19.3.

At present TGI does not contemplate the physical supply of LNG from Mt. Hayes to service TGI demand on the mainland because this supply can be done more economically by using the Tilbury facilities to supply LNG demand associated with transportation applications. The addition of the Mt. Hayes storage is a valuable resource that is integrated into overall system capacity planning and the addition of this resource increases the amount of LNG available at Tilbury for other market applications.

As demand grows direct supply of LNG from Mt. Hayes may be warranted to increase physical supply options and to secure a backup supply capability. This would require addition of an LNG truck loading facility at Mt. Hayes. In the event that LNG were to be transported from Vancouver Island to the mainland, it is unlikely that the transportation arrangements would include travel on BC Ferries. A more likely alternative would be to contract for carriage on the Seaspan Coastal Marine commercial freight service.

19.5 What other LNG supply options are available to LNG Service customers besides LNG sourced from the Tilbury or Mount Hayes facilities?

Response:

Other supply alternatives beyond Tilbury and Mt. Hayes would include Northwest Natural Gas Company's "(NWN") facility in Portland Oregon and the Chute Creek plant located in Wyoming. Other potential future supply locations for backup supply would include Northwest Pipeline Corporation in Plymouth and NWN in Newport Oregon.

20.0 LNG SUPPLY - RATE SCHEDULE 16

Reference: Exhibit B-1, Section 2.4.2, pp. 17-18; Commission Order G-65-09

As noted by TGI, Commission Order G-65-09, issued on June 4, 2009, approved Rate Schedule 16 Interruptible Liquified Natural Gas Sales and Dispensing Service as a five-year pilot.

20.1 Under Commission Order G-65-09, TGI is required to report on the results of the Rate Schedule 16 pilot program on an annual basis. Please provide a copy of the 2010 report.

Response:

Terasen Gas submitted this report to the Commission on February 4, 2011. A copy of the report is attached as Attachment 20.1.

In future years Terasen Gas intends to file this report on or before March 31.

20.2 Please discuss the impact that the expiry of Rate Schedule 16 effective December 31, 2014 and its categorization as a pilot has on TGI's ability to offer LNG Fueling Service.

Response:

The categorization of Rate Schedule 16 as a "pilot" and the expiry of Rate Schedule 16 effective on December 31, 2014 is a factor that limits the ability to sell LNG for transportation applications. Customers investing in LNG powered trucks require a long term service option and need to have the confidence that LNG will be available to service their needs. In TGI's experience, the designation of the Rate Schedule 16 as a pilot implies to some customers a temporary service that could be revoked, leaving them with facilities and trucks that cannot be used cost-effectively because currently the nearest alternative supply of LNG as transportation refuel is in Oregon. To date there has been no customer demand for LNG under this Rate Schedule, which reflects that customers are not comfortable purchasing LNG by the truckload and having to invest in and develop their own LNG storage and dispensing systems.

The present Application is a key requirement to achieve success of the Rate Schedule 16 Pilot. TGI believes that the projects the Company is developing within the model outlined in this Application will facilitate Rate Schedule 16 sales, with the result that TGI will better utilize core assets (Including Tilbury and in future Mt. Hayes) and generate revenues to the benefit of core customers as discussed in Section 3.1 of the Application. It is TGI's hope that the demonstration

of customer demand for LNG for transportation applications will lead to the Commission ultimately approving the continuation and expansion of Rate Schedule 16 service and removal of the "Pilot" designation.

21.0 LNG TRANSPORTATION TO CUSTOMER LNG FUELING STATION

Reference: Exhibit B-1, Section 2.3.2 and 2.4.2, pp. 18-20; Appendix C – Rate Schedule 16

"TGI's LNG Service offering includes owning and maintaining the following equipment:

- LNG tanker(s) – These are required for transport and delivery to the customer's fueling facility as the customer may not be able to self-provide such service;

... A separate delivery charge will also be created for the transport and delivery of the LNG should the customer require this service."

21.1 Please provide details regarding the nature of the delivery charge contemplated for this separate LNG transportation and delivery service and the methodology that will be used to determine it.

Response:

TGI proposes that the LNG transportation charge includes the cost of owning and maintaining TGI's LNG tankers as well as the transport costs for a driver and tractor to transport and deliver the LNG from TGI's LNG tanker to the LNG Fueling Station.

The LNG transportation and delivery service will include the following components:

- An allocation of the depreciation expense, earned return and incomes taxes associated with the capital cost of the trailer and based on the frequency of delivery needed;
- Allocation of the O&M costs associated with the trailer and based on the frequency of delivery needed; and
- Third party costs from the transport carrier charged at cost plus 15%. A transport carrier agreement has yet to be finalized, but this will likely consist of an hourly rate for the driver as well as a fuel surcharge and other possible incidentals.

Once these costs have been finalized, TGI proposes to create either a flat rate per delivery or charge per GJ, depending on what type of transport carrier contract the company is able to secure.

Please see Attachment 21.1 for a fully functional electronic copy of the model and an example of its use. In this example, the capital cost associated with the tanker is $275,000 and the annual O&M and transport carrier costs are estimated to be $85,000. Determining a delivery

charge per GJ based on a volume of 140 TJs per year results in an LNG transportation charge of $0.814/GJ in the first year.

This response also addresses BCUC IR 2.21.2 and 2.21.3.

21.2 Please include a fully functional electronic copy of the model and an example of its use.

Response:

Please refer to the Company's response to BCUC IR 2.21.1.

21.3 Will the cost of owning and maintaining TGI's LNG tanker trucks be included in the LNG Service charge and/or will this cost be incorporated in the separate delivery charge?

Response:

Please refer to the Company's response to BCUC IR 2.21.1.

21.4 How many LNG tanker trucks does TGI currently own and operate and what is the capacity of each tanker?

Response:

TGI currently owns and operates 2 LNG tankers.

1) 1971 Russell -capacity 10,700 US Gallons
2) 2010 Custom Alloy -capacity 11,300 US Gallons

Each tanker could be available up to 345 days a year for LNG Transportation. The remaining days would be used for maintenance, system support and outages.

21.5 Please provide details regarding the operating and safety requirements for transporting LNG by tanker truck from the Tilbury LNG facility to the LNG fueling facility.

Response:

This response also addresses BCUC IR 2.21.6.

Terasen Gas has considerable experience with LNG, production, dispensing from the Tilbury site, and transportation to end use customers. The operating and safety requirements required for transporting LNG by tanker truck as well as TGI's additional internal safety procedures are listed in the steps below. These regulations also form part of the terms and conditions of Rate Schedule 16.

1) **Dispensing of LNG** - Subject to section 13 of the General Terms and Conditions of Terasen Gas (Interruption of Service) and all of the terms and conditions of this Rate Schedule, Terasen Gas will on behalf of the Customer or the Customer's authorized agents dispense LNG into cryogenic trailers provided by the Customer or its contractor. This includes, but is not limited to the LNG tankers having a Transport Canada Registration Number, be certified for LNG use, registered for road transportation and displaying the proper placards. The loading of LNG into the tanker at Tilbury, will only be performed by qualified Terasen Gas personnel and there must be a certificate of last content to confirm it is suitable for LNG loading.

2) **Determination of Volume** - The quantity of LNG dispensed pursuant to Rate Schedule 16 shall be measured at the scale at the Tilbury plant that is approved and certified by Measurement Canada to determine the amount loaded on the LNG Tanker. The Customer will be weighed at said scale or alternate appropriate Measurement Canada scale before and after LNG Delivery. The measurement of the amount of LNG delivered shall be basedon the difference, expressed in kilograms, of these two weights.

3) **Title Transfer** - Possession of, title to and risk of loss of, damage to, or damage caused by the LNG sold and delivered hereunder shall pass from Terasen Gas to the Customer at Terasen Gas Tilbury LNG Operations, specifically, delivery and title transfer shall occur at the outlet flange of the tank truck upon loading of the LNG

4) **Transport Carrier** – The Customer warrants and represents that in its acceptance, transport, use or storage of the LNG is in compliance with the requirements of any laws, rules, regulations and orders of any legislative body, government agency or duly constituted authority now or hereafter, including, but not limited to, the federal Transportation of

Dangerous Goods Act. Drivers must have their Transport of Dangerous Goods designation as well as Terasen Gas requires all drivers that will be transporting an LNG tanker to go through a Terasen LNG Transport Training course. This consists of a classroom session that trains drivers on everything from the physical properties of LNG to emergency response. Terasen Gas also instructs the drivers on the safe operation of the trailer as well as hands on LNG training. A trained Terasen Gas LNG operator will accompany the driver for the first half dozen trips to further instruct and supervise the driver on the offloading of LNG at the LNG fueling station until Terasen Gas is satisfied the driver is able to fully complete a safe transport and delivery of LNG. Once complete and Terasen Gas is satisfied that the driver has met all safety requirements, the driver will receive certification from Terasen Gas to transport and deliver LNG from Tilbury.

5) **Documentation** – Terasen Gas shall be responsible for preparing and supplying all transportation and safety documents that are the responsibility of a consignor of dangerous good or a supplier of hazardous material or product under applicable laws and regulations including all safety marks, shipping documents and material safety data sheets (MSDS).

6) **Emergency Response Plan -** LNG is a commodity that falls under the regulations that requires the transporter to have a registered Emergency Response Action Plan in place that is approved by Transport Canada. As the supplier of this commodity, Terasen Gas represents and warrants that it has and shall maintain throughout the term of this Agreement an Emergency Response Action Plan approved by Transport Canada for the transportation of dangerous goods (the"ERAP"). Terasen Gas agrees that the ERAP shall apply to all LNG and LNG shipments until the LNG is delivered to and received by the Customer at its refueling station. Notwithstanding the foregoing, in the event that an accident occurs requiring implementation of the ERAP, the Customer shall reimburse Terasen Gas for all costs incurred to provide emergency response pursuant to the ERAP, including but not limited to, the dispatching of Terasen Gas personnel to the site of the accident. Unless the transport carrier has their own registered ERAP, Terasen shall provide this service for LNG transportation of LNG to the LNG Fueling station within TGI's service territory that is supplied from a TGI facility under both circumstances where TGI arranges the transportation or the customer arranges their own. TGI may at a future date contract this service to a third party provider should resources become an issue.

7) **Delivery / Offloading of LNG –** The safety requirements for the offloading of LNG at the customer LNG facility are discussed in BCUC IR's 2.17.1-2.17.6.

We believe our experience in the continued operations of Tilbury, soon to be commissioned Mount Hayes LNG Plant, and development and administration of past tariff offerings supports this proposal for LNG Service. Terasen Gas will use it leadership role to facilitate the safe and reliable development of LNG as a transportation fuel in BC.

21.6 Section 10 of Rate Schedule 16 sets out requirements regarding Emergency Response Action Plans, compliance with the federal Transportation of Dangerous Goods Act and preparation of Transportation and Safety documents related to the handling and transport of hazardous goods. Please describe which parties have responsibility for various safety and hazardous goods requirements for each of the possible scenarios where TGI provides the transportation of the LNG to the LNG Fueling station and where the customer arranges their own transportation assuming the LNG is supplied from TGI's Tilbury facility, TGVI's Mount Hayes facility or supplied from another source.

Response:

Please refer to BCUC IR 2.21.5.

22.0 USE OF BIOMETHANE AS VEHICLE FUEL

Reference: Exhibit B-1, Appendix F – Letters of Support

Several of the letters of support in Appendix F mention biomethane as a potential fuel source for NGVs; in particular the letters from the City of Surrey, the Columbia Shuswap Regional District and Wastech Service Ltd.

22.1 Does TGI contemplate building and operating fueling stations that use biomethane from landfills or food and yard waste processing facilities?

Response:

While it is possible that some potential biomethane projects may be developed in conjunction with an NGV refuelling project, it is TGI's intention to deliver biomethane notionally across the Terasen Gas distribution system from receipt points to NGV refuelling stations in a similar way to other biomethane customers. This business model was explored extensively in TGI's recent biomethane application and NGV customers demand for biomethane would be facilitated in a similar manner to other biomethane customers. The cited letters of support highlight the flexibility of the business model and highlight the fact that NGV can achieve greater GHG reductions through the use of biomethane. Terasen Gas is committed to serving the demands of our customers in a safe, reliable and economic manner, whether customers are demanding biomethane, NGV refuelling or both at the same time.

Where Biomethane is developed and introduced into TGI's system for notional use in NGV stations located on TGI's system, the tariffs and rate structures proposed under the Bio-methane application would be utilized. As contemplated in the biomethane application, biomethane would be made available to such customers as a percentage of their overall supply ranging from 10% to 100%. The customer tariff would be a blend of the percentages of biomethane and conventional gas using the respective costs of their supply pools.

In the case where a biomethane project fed a NGV station directly without entering TGI's system, a separate rate structure would likely need to be developed for the cost of biomethane supply.

In either case, there would be no impact on the development of the fueling station rate because the fueling station rate is independent of the type of gas being delivered and the rate class that the gas is delivered under.

22.2 Would this include situations where the biomethane does not enter the TGI distribution system? If so, what rate structure and tariffs would apply?

Response:

Please see our response to BCUC IR 2.22.1.

23.0 RISK OF STRANDED ASSETS

Reference: Exhibit B-1, Section 6.3, p. 65

As noted by TGI, a risk of stranded assets for CNG or LNG Service arises to the extent the term of the service agreement is less than the infrastructure asset life. TGI states that NGV stations are mobile and portable and can be relocated to other locations as a means of mitigating the risk.

23.1 Please comment on the mobility and potential for relocation of the components of a typical LNG Fueling Station. Which assets can be relocated and what portion of the overall LNG fueling station capital assets would be mobile assets?

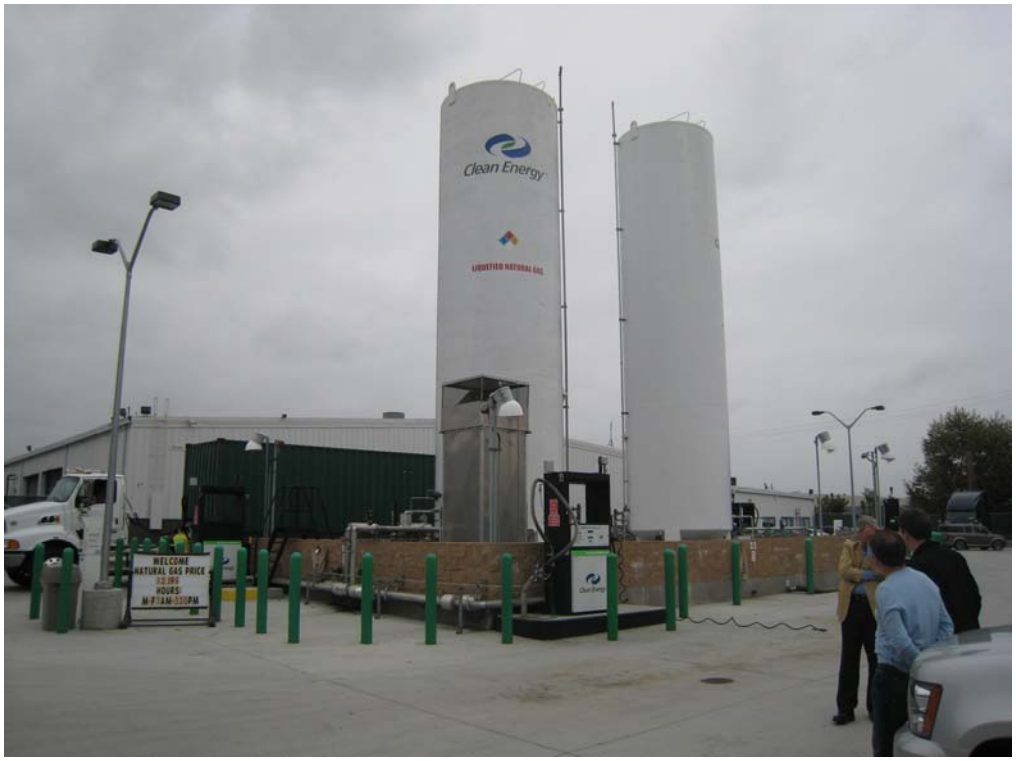
Response:

As discussed in response to BCUC IR 2. 18.1, there are two basic designs of LNG fueling station, one for larger volume accounts and one for lower volume accounts, although many variations on each are possible. The larger volume stations generally consist of the following elements:

- One or more LNG storage tanks
- One or two LNG pumps
- LNG dispenser(s) to deliver fuel to the vehicles
- Supply of utilities to the facility
- Associated controls and piping
- A secondary containment structure

An example of such a station is shown in the photograph below:

Photo 1 – Large Volume LNG Station Example – Los Angeles California



Terasen Gas recently commissioned Sacre Davey Engineering to develop a detailed cost estimate for a 20,000 gallon LNG facility similar to the one shown in the photograph. The estimated total installed cost of the facility is $1.7 million. Of this total $1.1 million or approximately 65% of the installed cost is the equipment supply component of the project (e.g. pumps, tanks, dispensers, valves & meters). The balance was made up primarily of engineering design costs and civil work such as site preparation and installation of foundations.

The equipment used within an LNG fueling station is mounted on slab foundations above ground. Hence it can be removed and redeployed to another site relatively easily. Tanks, pumps, dispensers, valves, meters and to some extend piping can be redeployed. Costs associated with site specific engineering design and installation of foundations and secondary containment structures is not portable to another site.

The situation is quite comparable for the Small Volume Station which is shown below. In this case the complete fueling system is housed within a 40 ft container which also acts as the secondary containment structure. In this case all that is needed is site preparation, installation of suitable foundations and supply of utilities. Terasen Gas estimates the cost of such a facility

to be approximately $700 to $750,000 and estimates roughly 65% of the total is portable to another location.

Photo 2 – Small Volume LNG Station Example – Apple Valley California

23.2 Please explain why the same factors that would depress the NGV market in British Columbia would not also tend to contemporaneously depress the NGV market elsewhere in North America.

Response:

To date there has been no market for LNG fueling infrastructure in BC, but there is a significant and growing market for such infrastructure in the US and other jurisdictions. The economics driving the need for stations include a variety of factors including government policy and incentive support programs. In the event that the market in BC faltered it is still quite conceivable that markets for these products would be strong elsewhere.

Terasen also notes that there is a growing market for use of LNG in stationary power and other industrial markets. This trend is exemplified by events such as The Downstream LNG Markets and Distribution Conference which was held in Houston on January 27th, 2011. The preview of the conference states:

"Downstream LNG distribution is growing at twice the pace of world LNG trade. Over the past decade, the market has averaged 15 to 20 percent compound annual growth. More and more LNG is being trucked, railed, and shuttled to LNG and LCNG-powered transportation, remote power generation, industrial markets, and needle peak shaving units. Worldwide, some 2,500 tanker trucks are transporting LNG, up from about 250 units in 1998. Increasingly, LNG is being distributed by rail and shuttle tanker as well. This one-day conference will review several national markets, including Norway, Sweden, Spain, Japan, the Dominican Republic, Puerto Rico and the United States. It will consider how and why downstream markets for LNG are growing and what may accelerate them into the future."
http://www.zeuslibrary.com/DLMD2011/index.asp

In the event that use in transportation markets falters it is possible that much of the equipment could be re-deployed into stationary power and other industrial applications markets. In addition the cryogenic equipment that is used for LNG storage can also be used to store other cryogenic products.

All of these factors combine to indicate that BC's market for LNG station equipment may not move in lock-step with market condition in other regions.

24.0 ADDITIONAL CNG AND LNG FUELING SERVICE APPLICATIONS

Reference: Terasen Utilities 2010 Long Term Resource Plan, BCUC IR 1.56.

"A transportation fuelling service application is being prepared to support new NGV initiatives and is expected to be filed by the end of 2010. This application will include approval for two specific projects for which funding commitments are required in conjunction with the development of the application: approximately $700,000 for a project targeted for completion in December 2010 and $300,000 toward another project scheduled for completion in 2011."

24.1 Please confirm that the subject Waste Management application is the first project referred to above.

Response:

Confirmed. The Waste Management project is the first project referred to. See also the response to BCUC IR 2.24.1 for other projects.

In addition, there are other projects in various stages of negotiations. This demonstrates that there is customer demand for NGV fueling services under the business model being developed and advanced by TGI.

24.2 Please provide details whether an application for the second project is planned to be submitted in 2011, the anticipated timing of such and the current status of the second project.

Response:

A school bus fueling project in Kelowna is under development. The Kelowna project is for a station to supply CNG to a fleet of school buses. In December of 2010, the Kelowna School District ("KSD") executed a purchase order for 11 natural gas buses. Terasen Gas is presently in the facility design stage and is negotiating terms for the fueling stations service agreement. The buses will be delivered in May 2011. The advanced stage of this project demonstrates the customer need for the refueling services proposed in this Application. An application for approval of a Tariff Supplement defining the Kelowna rate is expected to be submitted in March of 2011 after completion of the detailed design and cost projections and completion of negotiations with the KSD.

25.0 ADDITIONAL CNG AND LNG SERVICE APPLICATIONS

Reference: Westport Innovations Inc. Press Release dated December 21, 2010

A news release from Westport Innovations Inc., dated December 21, 2010 and posted on the TGI website, announces:

"that Vedder Transport Ltd. of Abbotsford, British Columbia has issued a purchase order for 50 Peterbilt 386 liquified natural gas (LNG) trucks featuring Westport HD Systems.

...Terasen Gas, a subsidiary of Fortis Inc., the largest distributor of natural gas in British Columbia, will fuel the Vedder Transport natural gas fleet through a planned LNG refuelling station in Abbotsford, which is expected to be built in 2011. In addition, Terasen Gas, through its Energy Efficiency and Conservation Program will offset the incremental cost of using LNG-powered trucks rather than their traditional diesel counterparts."

25.1 Please confirm if TGI is entering into a service agreement to provide LNG Service for Vedder Transport and, if so, provide details with regard to the status of negotiations, anticipated commencement date for service, the construction timeline, and anticipated timing for filing of an application for approval of the LNG Service agreement by the Commission.

Response:

Confirmed. TGI is working with Vedder Transport on a service agreement for supply of LNG Fueling Services for a fleet of 50 LNG tractors.

TGI is presently working with Vedder and Sacre Davey Engineering on the detailed design and cost estimate for this facility. A purchase commitment for 50 trucks was issued by Vedder in December 2010 and the first 10 trucks will be delivered in June 2011. The balance will be delivered on a schedule of 10 trucks/month between July and the end of October.

The latest project schedule estimates the completion of the permanent fueling station by October 1, 2011. The overall project plan also includes for provision of a temporary fueling facility that will be able to fuel the trucks by June 1, 2011.

TGI expects to be able to submit the Vedder agreement for Commission review and approval sometime in late February or early March, 2011.

25.2 Please provide an estimate of the monthly and annual volume requirements contemplated for the Vedder Transport fueling station referred to in the subject press release.

Response:

The 50 truck LNG fleet is expected to consume 138,000 GJ/year or 11,500 GJ/month. This incremental volume displaces approximately 3.6 million litres of diesel fuel consumption per year. A tank truck delivery of LNG to the Vedder station will be required approximately once every three days. This volume will be the first load supplied under Rate Schedule 16 and it will contribute approximately $537,000 per year in incremental revenue to TGI to the benefit of all customers. ($3.89/GJ * 138,000 GJ/year)

Production of LNG at Tilbury will generate incremental O&M cost associated with increased production of LNG at Tilbury and this cost will partially offset the revenue benefit referred to above. As discussed in the May 7, 2009 Rate Schedule 16 application, this incremental cost is estimated at $1.95/GJ or 52% of the rate. The remaining balance represents contributions that are incremental to existing O&M and capital accounts; thus they provide benefits to all rate payers.

The full rate breakdown estimate is shown below:

Table 1 - Rate Breakdown

O&M Charge- Liquefaction, Storage & Dispensing	$1.95
Capital Recovery	$0.97
Transportation from Huntingdon to Tilbury	$0.73
Peaking Arrangement Cost	$0.08
Total	**$3.73**

The $3.73 total charge has since increased to $3.89/GJ as a result of the annual rate adjustment as approved by the Commission (Order numbers G-141-09 / G-158-09).

The load added by the Vedder project is approximately 36% of the allowed volume cap under the Rate Schedule 16 tariff.

26.0 ASSESSMENT OF FUTURE PROJECTS

Reference: Exhibit B-1, Section 2.5, p. 20

"At this time, Terasen Gas has entered into discussion with a modest number of other NGV proponents to discuss the adoption of NGV service model similar to the one entered into with WM."

26.1 Please indicate the number of additional potential CNG and LNG Service customers for whom discussions have progressed to the stage that the customer has issued purchase orders for NGVs with the expectation it will receive Energy Efficiency and Conservation (EEC) funding and will enter into a CNG or LNG Service agreement with TGI.

Response:

As of January 28, 2011, the following commitments were made:

1. Waste Management (WM) – 20 garbage trucks
2. Vedder – 50 tractors
3. Kelowna School District – 11 School Buses
4. City of Surrey – 1 garbage truck

A fueling station agreement has been executed for the WM project. Agreements are in progress for Vedder and Kelowna. The City of Surrey has its own CNG fueling facility so no service is required at this point in time. Surrey has, however, indicated that the single truck it is ordering is to be used as a model for their next tender for refuse collection services which will require fueling services for a fleet of 50 trucks.

To date 82 heavy duty NGVs have been ordered for BC-based businesses. These vehicles will collectively displace approximately 4.4 million litres of diesel fuel consumption in BC reducing GHG emissions by 4,100 tonnes per year. The above NGV customers can expect to save an estimated $2.1 million per year in fuel costs. In addition these projects are expected to generate incremental revenues under existing TGI tariffs totalling approximately $596,616/year to the benefit of all TGI customers.

This incremental TGI revenue is broken down as follows:

Customer	Estimated Revenue/year
WM Delivery revenue under Rate Schedule 25[1]	$38,142
Vedder revenue Rate Schedule 16 (excluding commodity)[2]	$536,820
Kelowna revenue Rate Schedule 6 (6000 GJ @ $3.609/gj)	$21,654
TOTAL	**$596,616**

Notes:
[1] see response to BCUC IR 1.5.3
[2] see response BCUC IR 2.25.2

Note that the estimate is based on existing rates under Rate Schedule 25 for WM, Rate Schedule 16 for Vedder and Rate Schedule 6 for Kelowna.

The benefits of the incremental revenue on the WM and Kelowna projects flow through to the benefit of all customers as there is minimal incremental costs associated with servicing these customers under existing rate schedules. Surrey is not included as it has only 1 truck.

For the Vedder project approximately 52%of the incremental revenue is offset by incremental O&M costs. As detailed in the response to BCUC IR 2.25.2, the remaining $258k per year is a net incremental benefit that flows through to the benefit of all customers.

These projects are examples of real projects that can deliver the load building benefits described in Section 3.1 of the Application.

27.0 CUSTOMER AWARENESS

Reference: Exhibit B-1, Section 7 - Stakeholder Consultation

27.1 Does TGI have any plans to increase customer awareness of the CNG and LNG Fueling Service? If so, what means would be used and what is the anticipated cost?

Response:

TGI will continue to raise customer awareness of the CNG and LNG Fueling Service and the benefits of Natural Gas as transportation fuel, namely reduced emissions, and potentially lower, more stable fuel pricing. The main avenue to do this is to work with the customer directly using TGI's existing sales organization. In addition, TGI will continue to convey the NGV value proposition through industry associations and other influencers such as major vehicle distributers. By working within such existing sales channels TGI will have access to a large group of similar potential customers on a cost effective basis. TGI's sales strategy is based on early adoption of NGV's by Industry Leaders such as Waste Management. TGI will promote Reference Case models of NGV adoption with industry leaders to encourage others accounts to follow. The customer awareness activities summarized herein are already being pursued and are accounted for within existing TGI's O&M budget that formed part of TGI's 2010-2011 Revenue Requirements; hence there is no incremental cost to existing TGI customers from these activities.

28.0 EXTENSION OF TGI'S NATURAL GAS BUSINESS

Reference: Exhibit B-1, Section 2.4.2, p. 19; Utilities Commission Act

28.1 Are compression, storage and/or dispensing of LNG or CNG by TGI, for use by a singular customer at that location, activities that fall into the category described in (a) under the definition of "public utility" in section 1 of the Utilities Commission Act? Does the transportation of LNG by tanker by TGI to the LNG Fueling station fall into this category?

Response:

Yes, compression, storage and/or dispensing of LNG or CNG by TGI for use by a singular customer at that location are regulated activities because they meet the definition of "public utility". For ease of reference, that definition is set out below:

> **"public utility"** means a person, or the person's lessee, trustee, receiver or liquidator, who owns or operates in British Columbia, equipment or facilities for
>
> > (a) the production, generation, storage, transmission, sale, delivery or provision of electricity, natural gas, steam or any other agent for the production of light, heat, cold or power to or for the public or a corporation for compensation, or

Under this definition, the number of customers taking the service, and whether or not the facility is on the customer's own property, are not relevant factors in determining whether or not an activity is a "public utility" activity. Rather, the relevant factors are whether (a) TGI owns or operates the facilities in British Columbia [Yes], (b) the facilities are being used to provide natural gas service or "any other agent for the production of…heat" [Yes], and (c) whether the natural gas or heating agent is being provided "to or for the public or a corporation for compensation" [Yes. TGI is receiving compensation for the service. In most instances, the customers are going to be corporations, but in any event will be part of the public.]

A customer would not be subject to regulation as a "public utility" if it decided to own and operate the assets itself, only for the purposes of self-providing CNG or LNG, because it is not "providing service to or for the public or a corporation for compensation". Similarly, a service station (e.g. Shell, Chevron etc.) that "is not otherwise a public utility" would be exempt from regulation because, even though they provide "an agent for the production of heat", service stations are part of the "petroleum industry" exclusion in subsection (e) of the definition of "public utility". ["Petroleum industry" includes "(e) the retail distribution of liquefied or compressed natural gas".] The "petroleum industry" exclusion is inapplicable to TGI, however, because the exclusion only applies to entities that are not "otherwise a public utility", and TGI *is* otherwise a public utility. TGI observes that the phrase "not otherwise a public utility" in subsection (e) is express recognition that the Legislature contemplates a public utility being engaged in the "petroleum industry" as TGI is proposing in this context.

The transportation of LNG by TGI to the LNG Fueling station owned and operated by TGI is regulated for the same reasons as described above, i.e. it is part of the "petroleum industry" that is being provided by an entity that is "otherwise a public utility". Hence, the exclusion doesn't apply to TGI. There is no requirement in the definition of "public utility" that energy be delivered entirely by pipe.

28.2 Do these activities fall into the subject category described in 28.1 if the supply for the NGV Fueling station is a biomethane facility that is not connected to the TGI distribution system?

Response:

Yes, TGI's provision of biomethane would also be regulated since biomethane is an agent for the production of heat, and the other aspects of the "public utility" test outlined in the response to BCUC IR 2.28.1 are met. The fact that the facilities are not connected to the TGI distribution system is not relevant, since the scenario assumes that TGI still owns or operates the facilities for compensation from a corporation or the public.

28.3 If the Commission has concerns whether it is in the public interest for TGI to re-enter the CNG fueling station business, could the Commission require TGI to make a CPCN application for all new, or each new fueling station, so that the public interest can be examined?

Response:

Yes, the Commission has the jurisdiction to require a CPCN application for each new fueling station. However, TGI believes that our proposed review process for each contract is preferable for the following reasons.

First, the Commission will have already considered in the present Application the aspects of the public interest relating to GHG benefits and other British Columbia's energy objectives. While the *amount* of GHG benefits, and the *degree to which* British Columbia's energy objectives are met, may differ from project to project, the fact that there are benefits will be consistent in all cases.

Second, TGI will be submitting each contract to the Commission for approval as a just and reasonable rate. The contracts are going to stipulate "take or pay" rates that recover the forecast cost of service occurring during the contract term. Provided that the Commission is satisfied that (i) the forecast cost is reasonably accurate, that (ii) the rate indeed recovers the forecast cost of service occurring during the contract term, and that (iii) the other terms in the agreement allocate cost risk appropriately, that should be sufficient protection to existing customers. The additional throughput will be what provides benefits to all customers, and that can be calculated from the "take or pay" volume. A formal CPCN process (which would necessitate revisiting matters such as GHGs) is not required for the Commission to undertake this analysis and to ensure that existing ratepayers are protected.

Thus, TGI believes that the Commission's review of the contract is more than sufficient to be able to ensure that the public interest is served and that customers are protected.

29.0 CNG AND LNG FUELING AS A NON-REGULATED SERVICE OFFERING

Reference: Exhibit B-1, Appendix A-2, p. 7; Utilities Commission Act

"From the period of 1999-2005, Terasen Gas formed a separate non-regulated company in order to have greater flexibility to grown (sic) the NGV market and own and operate natural gas fueling stations across North America."

29.1 Please explain if there is any reason, given the definition of "public utility" under the Utilities Commission Act, that Terasen Inc. or TGI could not again set up a non-regulated business to own and operate NGV fueling stations in British Columbia? If so, does this include the transportation of LNG by tanker truck?

Response:

As explained in the response to BCUC IR 2.28.1, TGI's CNG and LNG service is subject to regulation because it is "otherwise a public utility", making it ineligible for the exclusion that applies to entities engaged in the "petroleum industry" (such as gas stations). TGI confirms that another Terasen Inc.-owned entity that was not "otherwise a public utility" (i.e. not otherwise engaged in the sale of services that are subject to regulation by the Commission) could engage in the sale of CNG and LNG without being subject to regulation by the Commission as a "public utility". This would include transportation of LNG by tanker truck.

However, Terasen Inc. is interested in owning and operating NGV fuelling stations only through its regulated utility subsidiaries, specifically TGI, in the manner proposed. The proposed service is a natural extension of TGI's regulated business and our proposed offering adequately protects existing customers.

29.2 Does TGI or Terasen Inc. currently hold an ownership stake in Clean Energy, the company that acquired the NGV fuelling stations from TGI?

Response:

No, neither Terasen Gas nor Terasen Inc. has any ownership stake in Clean Energy. Terasen Inc. sold their remaining stake in Clean Energy in 2005.

30.0 GOVERNMENT SUPPORT FOR NGV

Reference: Exhibit B-1, Section 3.3, pp. 34-45

30.1 Given the increasing focus of government policy on reducing GHG emissions, would it be reasonable to expect that government actions in the near future may stimulate customer interest in NGV fueling to the extent that customers may be incented to provide their own fueling facilities to switch from diesel or gasoline to NGV fuel?

Response:

The scenario that the question envisions is a possible one, however it is not presently the case. There remains a capital cost barrier for the acquisition of NGV technology that, in the absence of incentive funding, would require government action in the form of prohibitions or significant price signals to overcome.

High-level discussions between Terasen Gas and the Provincial Government have indicated the government's continuous support of TGI's NGV initiatives, consistent with what was indicated in their letter of support for the 2010-2011 Revenue Requirements Application Negotiated Settlement Agreement approved by Order G-141-10 (Attachment 30.1 contains the letter).

In addition, TGI believes that the complexities of owning and operating fueling station assets are beyond the typical capabilities of most fleet managers, who do not have experience owning and operating assets for high pressure gas delivery or cryogenic fuel delivery. Addition of government incentives will increase customer desire for NGV fueling facilities but will not address the fundamental customer limitations with respect to experience base and technical capability.

30.2 Would governments be less likely to provide incentive funding for NGVs if there is a funding mechanism already in place through the utility?

Response:

Terasen Gas is not in a position to speculate on the likelihood of the actions of government other than formally announced government activities and the high-level discussions articulated in our response to BCUC IR 2.30.1. As indicated in attachment to the response to BCUC IR 2.30.1, the provincial government supports TGI's NGVs initiatives.

However, it should be noted that the legislation currently in place requires that public utilities play a role in providing demand side measures, and that demand side measures must be considered in light of "British Columbia's energy objectives". "British Columbia's energy objectives" expressly include "to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia." TGI believes that it would be inconsistent with the legislated objectives for the Commission to decline incentive funding for NGVs in the hope that the Province fills the gap with funding or other methods of encouraging NGVs.

31.0 CNG AND LNG SERVICE RATE DESIGN AS MEANS OF REDUCING FUEL PRICE VOLATILITY

Reference: Exhibit B-1, Section 3.2.2, p. 33

"the second key benefit associated with NGV service offered by TGI is that it tends to be subject to less volatility than diesel or gasoline. Although the underlying volatility of natural gas, oil and gasoline may be similar, how these prices get reflect (sic) to customers may be somewhat different. .... For fleet operators, a fixed fueling charge such as $5/GJ contributes to a smoother, more predictable net fuel price on a diesel litre equivalent basis."

31.1 Over and above the provision of a fueling facility, is the proposed CNG and LNG Service offering being marketed to customers as a means of reducing fuel price volatility through its rate design features, specifically the use of forecast rather than actual costs and the use of fixed escalation factors?

Response:

Reduced fuel price volatility, as measured at the point of delivery into the vehicle's fuel tank, is one element of the overall value proposition for using natural gas to fuel transportation applications. As such it is one of the points TGI uses in discussions with potential customers.

There are three main components that go into the end price of fuel delivered to the vehicle. These are commodity cost, delivery cost and dispensing costs. Costs associated with the supply chain elements (delivery cost and dispensing costs) for diesel and for natural gas are easily predicted and are relatively stable over time. The commodity cost, however, fluctuates according to the supply and demand characteristics for each commodity.

Taking the example of a natural gas station delivering compressed natural gas to a vehicle under Rate Schedule 6 (January 2011), the various elements are as follows:

Commodity	$4.921
Delivery	$3.609
Compression & Dispensing	$6.000
Total (pre-tax)	$14.53

As seen in the example commodity only represents 34% of the cost of fuel delivered to the vehicle. In this example the commodity price is $0.19 per diesel litre equivalent. The commodity

component of diesel is measured by the rack price of diesel at the distribution terminal. This cost is a much higher fraction of the total delivered cost of fuel to the vehicle tank. As of January 29, 2011 the rack price of Ultra Low Sulphur Diesel in Vancouver was $74.40/litre.

The reduced fuel price volatility is a result of the fundamental cost structure of the supply chain for delivering Natural Gas rather than the proposed practice of using estimated fueling station capital costs as opposed to actual construction costs in the development of the Compression and Dispensing rate.

31.2 If so, has TGI determined the value to the customer of a smoother, more predictable net fuel cost? Please quantify how the intrinsic value of reduced fuel price volatility has been incorporated in the determination of the rate.

Response:

No, TGI has not determined such a value to the customer. The value of reduced fuel price volatility to end users will depend on the end user's specific circumstances and the price elasticity of the markets they compete in. Some customers have the ability to pass on such costs and others may not. TGI has made no attempt to place a value on this element of the total value proposition for Natural Gas as a transportation fuel as it will vary for each application. Further, as discussed in BCUC IR 2.31.2, the reduced fuel price volatility in comparison to diesel pricing is primarily a result of the fundamental cost structure and rate setting of the supply chain for delivering Natural Gas, not the structure of the CNG/LNG rate.

Under the proposed GT&Cs, the rate will reflect the cost of service, without a premium to reflect the attributes of natural gas service.

32.0 BC'S ENERGY OBJECTIVES - RENEWABLE PORTFOIO STANDARDS

Reference: Exhibit B-1, Section 3.3.1.1.2, p. 37

"Some key points to note:

- Conventional CNG has a net carbon intensity value that is 38% lower than reformulated gasoline and 28% lower than ultra-low sulphur diesel."

32.1 Please provide the carbon intensity of biodiesel.

Response:

The carbon intensity values stated in the question were based on information available in the Low Carbon Fuel Regulation Requirements (LCFRR) Intentions Paper.[6] This source also provides the carbon intensity of biodiesel from multiple feedstocks, which are summarized in the table below. TGI has also included CNG from biomethane sources for comparison.

Feedstock Description	Base Carbon Intensity (gms CO_2e /MJ)	Engine Efficiency Factor	Adjusted Carbon Efficiency (gms CO_2e /MJ)	% reduction vs. ultra-low sulphur diesel
Biodiesel:				
Soybean (US Midwest)	56.75	1.2	47.29	39%
Canola (Western Canada)	10.33	1.2	8.61	89%
Palm oil derived	35.45	1.2	29.54	62%
Tallow	-2.56	1.2	-2.13	103%
Yellow Grease	-4.61	1.2	-3.84	105%
Compressed Natural Gas ("biomethane"):				
CNG from landfills	6.76	1.1	6.15	92%
CNG from an anaerobic digester	-3.25	1.1	-2.95	104%

While biodiesel sources hold lower carbon intensity values than CNG and LNG, there are significant challenges and practicalities associated with its production and availability.

At present, BC biodiesel production is highly constrained. The Canadian Renewable Fuels Association states that BC's capacity is only 21 million litres per year, which is around 10% of Canada's operational capacity.[7] This could be attributed to poor economics and a lack of

[6] LCFRR Intentions Paper

[7] Canadian Renewable Fuels Association http://www.greenfuels.org/en/industry-information/plants.aspx

government funding incentives. Importing biodiesel feedstock may require long transport distances, which would increase the total lifecycle assessment and diminish the GHG emissions reductions benefit.

As shown in the above table, biomethane from landfills and anaerobic digestion (delivered as CNG) hold carbon intensity values equivalent or lower than biodiesel. Not unlike biodiesel, biomethane supply is presently constrained in BC; however, TGI's Biomethane service offering aims to develop supply in the near term. Biomethane as a transportation fuel could be implemented over the long term.

BC's natural gas resources are abundant, accessible, and low cost. Approval of this Application would allow transportation customers to receive CNG and LNG in a usable form and allow TGI to provide an end-to-end service offering.

TGI believes conforming to the LCFRR will require conventional fuel suppliers in BC to seek an integrated fuel solution to meet the carbon intensity baseline. This includes the adoption of biodiesel and ethanol sources, as well as natural gas and electricity. TGI foresees no single solution, meaning numerous alternative fuel sources will play a role in meeting the regulation.

33.0 STAKEHOLDER CONSULTATION AND LETTERS OF SUPPORT

Reference: Exhibit B-1, Section 7, p. 67; Appendix F

The Application states that TGI has consulted with a number of stakeholders over the two years leading up to the filing of this Application.

33.1 Please describe the format used by TGI when carrying out the stakeholder consultation. For example, was it a workshop presentation, an individual key account manager meeting with customers or other forms? Did TGI combine the customer groups with potential project partners in a consultation session?

Response:

Over the two years leading up to the filing of the Application, TGI conducted extensive stakeholder consultations which helped TGI shape the Application. The extent of the stakeholder consultation process is described in Section 7 of the Application on pages 67 through 69. In Section 7 TGI describes consultation efforts opposite customer organizations, technology suppliers, industry associations, fuel providers, equipment dealers, government entities and first nations. The format followed by TGI in consulting with these stakeholders was generally a face to face meeting. In some cases discussions took place within meetings organized by industry associations such as the Canadian Natural Gas Vehicle Alliance. In other cases, TGI representatives participated in joint presentations with NGV equipment suppliers such as Westport innovations, Cummins Westport and IMW. In general TGI did not combine customer groups with project partners, however, TGI did participate in combined sales presentations to individual customers such as BC Transit.

33.2 Please provide a sample of presentation materials to the customer groups and potential project partner groups in your response.

Response:

Please refer to BCUC IR 2.33.1.

33.3 Appendix F contains Letters of Support from 18 organizations. If TGI's applied for GT&Cs for CNG and LNG Service are approved by the Commission, please describe how many of the 18 organizations would be: (i) potential customers for

natural gas with potential use of the TGI's distribution system; (ii) potential customers for natural gas without potential use of TGI's distribution system; and (iii) potential project partners.

Response:

Appendix F contains 18 letters of support for TGI's applied for CNG and LNG service, submitted by 17 Organizations (School District No. 23 submitted two letters). These 17 Organizations all believe that Natural Gas for Transportation is a solution that will reduce emissions while providing lower and more stable fuel prices in comparison to diesel, and that Terasen is best positioned to offer this service given its expertise and knowledge. The 17 Organizations can be categorized into the following groups:

- 11 Potential Customers (12 letters)
- 5 Potential Project Partners (5 letters)
- Industry Association (1 letter)

Of the 11 potential customers that sent in letters of support, all 11 would have the potential to use natural gas and TGI's distribution system. There would be zero potential customers for natural gas without the potential for use of TGI's distribution system and all 5 of the potential project partner's category would be potential project partners.

33.4 In the Terasen Utilities 2010 Long Term Resource Plan (Section 3, page 61), it states that TGI has formulated an Innovative Technologies portfolio, and has made particular progress which included initiating a pilot incentive program to encourage operators of heavy duty fleets such as garbage trucks and waste haulers to switch to natural gas from higher-carbon diesel. Out of the 18 organizations that provided Letters of Support, how many of them have provided TGI with Expressions of Interest to use EEC incentive to purchase new natural gas vehicles for garbage collection and transfer operations?

Response:

As stated in BCUC IR 2.33.3 of the 17 Organizations that submitted letters of support, 11 are actual potential customers. TGI has, to date, received five Expressions of Interest to use EEC Incentive to purchase new natural gas vehicles - four of which were for garbage collection and transfer operations.

34.0 NGV LOAD AS COST EFFECTIVE LOAD

Reference: Exhibit B-1, Section 3.1, p. 22

The Application states that NGV load will serve to mitigate some of the delivery rate pressure that existing customers may face in years to come as natural gas demand for heating declines.

34.1 Can TGI confirm that all NGV load can be considered cost-effective load? Could the conversion of landfill gas to LNG for the operation of trucking fleet for a municipality be considered cost-effective to the customers of TGI?

Response:

TGI confirms that, as proposed, NGV load will only be added if it is expected to be cost-effective from the perspective of existing customers. The cost-effectiveness of new NGV load from the perspective of existing customers is ensured by performing two analyses:

1) Any system improvements, if required, to provide natural gas to an NGV fueling station would undergo a main extension test. This is consistent with existing TGI practices.

2) TGI's cost of service model described in the Application ensures NGV load is cost-effective through take-or-pay service agreements with the customer.

The addition of the cost-effective NGV load serves to mitigate some of the delivery rate pressure that existing customers may face in years to come as natural gas demand per account or in total for heating declines.

TGI has not yet analyzed a biomethane for NGV program. In considering the issue of cost effectiveness, it is important to keep in mind the distinction that the cost of Biomethane is a commodity cost issue, while the LNG rate is a charge for LNG Service. The cost of Biomethane, under TGI's current Biomethane program, is determined with reference to the cost of production of Biomethane. By contrast, the proposed rate for LNG dispensing service is determined with reference to the cost of providing the LNG Service. The NGV load would be cost-effective for existing customers assuming that the Biomethane continues to be priced in the current manner, the MX test is met, and the LNG fueling charge has been set in the manner proposed to recover the forecast cost of service over the term of the agreement.

34.2 In this Application, does the demand for NGV load necessarily lead to demand for fueling infrastructure? Is the demand for fueling infrastructure in B.C. the same as demand for TGI fueling structure?

Response:

For the purposes of preparing a preliminary demand forecast, TGI has made the assumption that NGV load generally leads to demand for fueling infrastructure. However, in some cases, a fleet operator who already operates a fueling station may add more vehicles without infrastructure upgrades. Therefore, TGI adjusted its station forecast by applying a station redundancy factor, which is described on page 20 of Appendix A-1 in the Application.

BC fueling infrastructure demand does not necessarily equal TGI fueling infrastructure demand. TGI is not focused on providing fueling infrastructure for the public, passenger vehicle market in BC. Any future NGV adoption in this segment would not necessarily be served by TGI's fueling infrastructure, as the proposed business model in its current form is not designed to serve this market. TGI's proposed business model does not preclude other market participants, although at this time no other participants have committed to developing the BC fueling station market. TGI's demand forecast does not assume TGI has a monopoly of the fueling station infrastructure in BC.

34.2.1 Please explain if the figures in Table 3-1 on page 24 of the Application are based on the assumption that TGI has a monopoly of the future fueling infrastructure in B.C.

Response:

No, the assumption is not that TGI has a monopoly of future fueling infrastructure in BC. The demand forecast figures are not necessarily tied to fueling infrastructure. TGI believes there is market potential for 30 PJ, 13 PJ and 36 PJ for respectively Reference Case, Low Growth, and Plus Passenger Growth. The revenue benefits described in the cost-benefit analysis (on page 24 of the Application) only consider revenues from existing Transportation Rate Schedules, and TGI would provide this service irrespective of the ownership of the fueling facilities. TGI's proposed fueling service charges, which would be affected by the ownership of the fueling facilities, are not included. Therefore, even if new market participants entered the fueling infrastructure market, the benefits to new and existing customers in this analysis would remain the same, all else equal.

35.0 DEMAND FORECAST SCENARIOS

Reference: Exhibit B-1, Appendix A1, p. 16

The Application forecasts that by 2030, there is market potential for 30 PJ, 13 PJ and 36 PJ for respectively Medium, Low Growth and Reference Case Plus Passenger Growth scenarios.

35.1 In order to put the forecast market demand potential of energy use for NGVs into perspective, please provide in tabular format, for the years 2012, 2015, 2020, 2025 and 2030, the natural gas throughput in the traditional business of the Terasen Utilities.

Response:

Please see attached for a live spreadsheet which summarizes the Terasen Utilities' traditional natural gas demand forecast organized by TGI – Coastal, TGI – Interior, TGVI and TGW. The underlying assumptions and detailed description of this demand forecast can be found in the 2010 Long Term Resource Plan.[8]

The table below summarizes the Terasen Utilities Reference Case demand forecast and compares it with the NGV Reference case demand forecast. As described in the 2010 LTRP, the Terasen Utilities' demand forecast does not include NGV volumes.

	Demand Forecast (TJ)				
	2012	**2015**	**2020**	**2025**	**2030**
Terasen Utilities	175,501	173,761	175,696	177,167	178,237
NGV - Reference Case	468	1,440	6,228	15,968	29,753
NGV as % of TU	0.27%	0.83%	3.54%	9.01%	16.69%

Traditional natural gas forecasts show that annual demand growth appears to be levelling, with declining use rates being offset by growth in customer numbers. Incremental NGV load can help to offset declining use rates and benefit all customers. NGV load is also flat and predictable, which can improve system efficiencies.

NGV demand represents a very modest and reasonable contribution to the TU business over the near-term. Over the long-term, the heavy duty transportation sector in BC represents a large potential opportunity to increase natural gas throughput on the Terasen Gas system and benefit new and existing customers through lower delivery rates all else equal.

[8] Assumptions can be found in Section 4.2 (page 75) with data in Appendix B-2 of the 2010 LTRP.

36.0 DEMAND FORECAST ASSUMPTION

Reference: Exhibit B-1, Appendix A1, pp. 11-12, 18

Pages 11 and 12 describe six steps in the demand forecast methodology and step 2 refers to the assessment of the strength of the value proposition for natural gas within that segment versus competitive options.

36.1 The assumptions underlying the Reference Scenario on page 18 of the Appendix do not appear to include the assumptions on the competitiveness of NGV versus other new and clean technologies in either the public transportation or heavy vehicle sectors. What are TGI'S assumptions regarding the adoption of hydrogen bus and hybrid electric diesel vehicles over the forecast period in the Reference Case?

Response:

The intent of providing these scenarios was to provide a range of possibilities that reflects TGI's view of the range of outcomes that may result from our NGV market development activities. The demand scenarios are, however, forecasts of possible developments in an emerging market and are therefore subject to inherent uncertainty. TGI's proposed business model only considers market development (i.e. fueling stations) to meet demand when "take-or-pay" service agreements are established with fleet operators. Therefore existing TGI customers bear very little risk of having to fund the costs of this service, while still creating an opportunity for present and future customers to obtain the benefits associated with TGI providing NGV service.

TGI believes the strength of value proposition for natural gas is greater than other fuel types such as hydrogen or hybrid electric. Due to the current costs and technological limitations of the two latter technologies, TGI does not believe they represent a viable solution within today's heavy duty vehicle market. Therefore, TGI has assumed the adoption hydrogen and hybrid electric vehicles to be negligible in the Reference Case.

Finally, TGI is not focused on developing the passenger vehicle market. The adoption of hybrid electric vehicles in this segment may occur, but TGI has not performed such analyses as it appears to be outside of the scope of this Application.

37.0 MARKET SHARE OF FUELING STATIONS

Reference: Exhibit B-1, Appendix A1, p. 21

TGI's preliminary estimates are such that it would operate approximately 25 to 30 per cent of all natural gas fueling infrastructure in B.C. within the heavy duty and bus segments, as well as 40 per cent of marine fueling stations.

37.1 Please translate what the above percentage shares mean in terms of the forecast total number of fueling stations in B.C. for the following segments -- heavy vocational trucks, heavy duty trucks, and buses.

Response:

The following table summarizes TGI's forecast compared to the total potential number of fueling stations in BC.

	Number of Fueling Stations in 2030		
Category	**TGI**	**Total**	**TGI as % of Total**
Heavy Vocational Trucks	61	242	25.3%
Heavy Duty Trucks	118	403	29.3%
Buses	20	63	32.0%

TGI's fueling station estimates are based on the assumption to meet a demand forecast of approximately 30 PJ of NGV load in 2030. The 30 PJ forecast also includes commercial, return-to-base light duty trucks, medium duty trucks and marine segments.

TGI's proposed business model does not preclude other market participants, but at this time TGI is not aware of other participants whom have committed to developing the BC fueling station market.

37.2 Are all the fueling stations 'return-to-base' fueling stations? What is the average energy use per fueling station?

Response:

Yes, the preliminary estimates of fueling stations are based on TGI's proposed 'return-to-base' business model, as described in the Application.TGI is not targeting the public fueling infrastructure market or 'stranded' fleets with this Application.

The average energy use per station is summarized in the table below.

Category	Station Capacity	Average Energy Use Per Vehicle (GJ)	Average Energy Use Per Station (GJ) [9]
Heavy Vocational Trucks	50	800	40,000
Heavy Duty Trucks	30	2,500	75,000
Buses	50	1,840	92,000

The station capacity estimates are based on data provided to TGI by fueling station engineers. The underlying assumptions for average energy use per vehicle are described in Appendix B-8 of the 2010 Long-Term Resource Plan.

37.3 What is the basis of estimating 25 to 30 percent market share for TGI. Please include the advantages and disadvantages TGI has compared to its competitors (if any) in providing fueling stations service to vehicle fleet.

Response:

At present, there are no other significant fueling infrastructure services operating in BC, however, TGI's business model does not preclude other market participants. TGI's forecast is based on the total addressable heavy duty transportation market in BC, assuming conversion to natural gas.[10] Since other market participants are not presently active in the BC market, TGI is not in a position to assess comparative advantages or disadvantages in relation to existing market participants. TGI can however, summarize the strengths of its value proposition, which are:

- Proven expertise and knowledge in LNG production, storage and transportation. Experience in the ownership and operation of CNG fueling stations.
- Established, reliable, and reputable integrated energy provider. Customers may be more willing to agree to long-term service agreements with a partner like TGI.

[9] Calculation: station capacity multiplied by average energy use per vehicle equals average energy use per station

[10] TGI's forecast number of vehicles were divided the by the station capacity assumptions stated in the response to BCUC IR 2.37.2 for each vehicle category.

- Potential of a lower cost of capital. This translates to an ability to offer a lower service charge over the term of the agreement to customers.
- No premium on commodity gas. Competitors may seek to charge customers a marginal rate on the cost of gas, whereas TGI is not permitted to do so by regulation.
- Single focus on developing the BC transportation market. TGI is not concerned with developing markets outside of BC.

In summary, TGI believes that it can play a role in providing CNG and LNG Service in BC which is fair and reasonable for all ratepayers. TGI's model does not preclude other market participants, but at this time no other participants have committed to developing the BC fueling station market. TGI's 25 – 30% market share is based on the underlying assumption that its entire forecast target market adopts NGVs.

38.0 OWNERSHP AND VALUE OF CARBON CREDITS

Reference: Exhibit B-1, Section 3.2.3.1, pp. 33-34

"TGI may consider negotiating in future NGV agreements that Terasen Gas is entitled to any GHG emission reductions as a result of the provision of the proposed NGV service offerings or EEC incentives for NGVs. Therefore, if multiple projects qualify, TGI could undertake, on an aggregate basis, third party validation and verification and the establishment of accepted protocols for these projects. Treatment of any carbon credits resulting from TGI's proposed NGV service offering or EEC NGV initiatives has not been resolved at this time."

38.1 Has TGI made any commitments to date to any parties to agreements for proposed CNG or LNG Fueling Service offerings, including Waste Management, regarding treatment of any carbon credits?

Response:

The ownership of potential carbon credits is a commercial term that the Company intends to negotiate as part of the overall negotiations between NGV customers and TGI. This term did not appear in the current WM Agreement for the reasons discussed in BCSEA IR 2.25.1 and in BCUC Confidential IR 2.7.2. TGI made no commitments with respect to carbon credits in the WM Agreement, and has not, to date, formalized any NGV related agreements that include commitments with respect to ownership of environmental attributes.

Since TGI currently in the early stages of developing the NGV vehicle fueling station business, TGI is still in the process of determining whether the EEC Fuding Agreement and/ or the fueling station agreement is the most logical and appropriate place to address ownership of any environmental credits related to a customer switching from diesel to natural gas to fuel its trucks. TGI intends to retain flexibility to achieve a negotiated solution with a CNG or LNG fueling station customer and to obtain the most suitable mechanism in the future in the negotiation of terms with respect to carbon credit ownership in the context of the fueling station service agreement. The Commission will be able to review any CNG or LNG Service Agreement to ensure that the terms are just and reasonable.

Please also refer to BCUC IR's 2.38.2, 2.40.1 and BCSEA IR 2.25.3.

38.2 Would TGI undertake third party validation and verification as part of a regulated service offering or a non-regulated business?

Response:

This response also responds to BCUC IR 2.38.3 and 2.39.1.

TGI would propose to aggregate carbon reductions and coordinate third party validation and verification as part of a regulated service offering, so the benefit of the monetization of any carbon offsets from TGI programs would go back to ratepayers in some manner. TGI would expect the revenues from selling the carbon offsets would reduce customer rates or reduce the amount of EEC incentive funding needed for NGV customers by flowing the revenues into an NGV funding bucket. [As stated in other responses, TGI will obtain the most logical and suitable mechanism to address the benefits.] Additionally, in the case of a regulated market (such as cap and trade), TGI retaining the GHG reductions could be a more cost effective solution for customers than having TGI purchase carbon offsets or allowances on the open market for compliance purposes.

B.C. public sector organizations and municipal governments will likely wish to retain the emission reductions associated with reducing their carbon footprint to meet their respective requirements under the Greenhouse Gas Reduction Targets Act or the Climate Action Charter. These provincially run organizations and local governments would be responsible for measuring and reporting their greenhouse gas footprints. In these cases, TGI would likely not be successful in negotiating ownership of the GHG reductions as these organizations are mandated to reduce and TGI would work with these organizations to ensure the GHG reductions flow through to their organization and are not double counted or cross-subsidized. These government entities are likely to be particularly interested in retaining these rights because they have a means of readily converting them to a benefit, i.e. recognition under the GGRTA or Climate Action Charter.

In order for any other entity (including TGI) to obtain some benefit from a reservation of rights, they would have to incur the costs and work necessary to convert the reductions to offsets. There are significant costs in the creation of carbon offsets, including creating project plans, developing protocols, validation and verification of greenhouse gas reductions. Many projects may not be able to efficiently participate in this developing carbon market on an individual basis as it would be cost prohibitive to do so. Terasen Gas believes it would add value acting as an aggregator of the GHG emissions reductions in qualifying projects. Reductions not retained by the customer could be pooled to achieve the economies of scale required to successfully participate in the offset market.

However, there are risks associated developing and holding offsets in a rapidly changing carbon market. These include changing regulatory criteria, project risk, aggregation and certification costs, and the cost of offset in an emerging market. Terasen Gas is in the process of developing a business model to address these issues, so at this point TGI is only negotiating contractual language, where it is appropriate to do so, giving it ownership of potential GHG

reduction benefits arising from a project. Once the business model is finalized, the Company will determine whether, in the current regulatory framework it is appropriate to move forward with the validation and verification of greenhouse gas emission reductions that Terasen Gas owns.

38.3 If TGI negotiates ownership of the carbon credits, describe the ways the other ratepayers might benefit from such ownership and the risks and liabilities that might potentially be associated with such ownership.

Response:

Please refer to BCUC IR 2.38.2.

39.0 OWNERSHIP AND VALUE OF CARBON CREDITS

Reference: Exhibit B-1, Section 3.2.3.1, pp. 33-34

The Application states that it is unlikely that validating and verifying emission reductions on an individual project basis would be cost effective for participating customers.

39.1 If provincially run organizations and local governments in B.C. have adopted policies and/or regulations relating to environmental sustainability, reducing carbon foot print or to become carbon neutral in city operations by 2012 (Climate Action Charter), would local governments be responsible for measuring and reporting greenhouse gases?

Response:

Please refer to the Company's response to BCUC IR 2.38.2.

40.0 OWNERSHIP AND VALUE OF CARBON CREDITS

Reference: Exhibit B-1, Section 3.2.3.1, pp. 33-34

The Application states that TGI may consider negotiating in future NGV agreements that TGI is entitled to any GHG emission reductions as a result of the provision of the proposed NGV service offerings or EEC incentives for NGVs.

40.1 Where there may be additional value in monetizing GHG emission reductions as offsets, would it be more efficient for the participating customer to claim the carbon credits or offsets and for TGI to put EEC funding to more cost-effective use than to fund the incremental cost for NGV?

Response:

TGI does not believe it would be more efficient for a customer to claim carbon offsets rather than TGI providing EEC funding to cover incremental cost of an NGV. Terasen Gas believes EEC funding is appropriate and provides the incentive needed to make it economical for customers to implement solutions using natural gas as a low carbon transportation fuel. Terasen believes that the incremental cost of switching fleet vehicles to natural gas is a market barrier and any carbon tax reduction and potential carbon offset value is not driving customers to make this decision.

The value of a carbon offset on its own does not make a large enough impact to offset the incremental cost to the customer of acquiring natural gas vehicles. For example, a CNG-powered refuse truck driven 45,000 kilometres per year in B.C. is estimated to produce about 15 fewer tonnes of carbon emissions annually than its diesel counterpart[11]. The Pacific Carbon Trust currently advertises that offsets can be purchased for $25 / tonne[12]. Assuming this market price, this would translate into only $375 / year that a customer could monetize and put towards offsetting the incremental cost of a CNG engine, which is currently between $35,000-$55,000 more than its diesel counterpart. However, TGI could aggregate projects together and these GHG reductions could be monetized in a more cost effective manner with the benefits going back to the ratepayers in some manner. As discussed in BCUC IR 2.38.2, TGI would expect the revenues from selling the carbon offsets would reduce customer rates or reduce the amount of EEC incentive funding needed for NGV customers by flowing the revenues into an NGV funding bucket. Additionally, in the case of a regulated market (such as cap and trade), TGI retaining the GHG reductions could be a more cost effective solution for customers than having TGI purchase carbon offsets or allowances on the open market for compliance purposes.

[11] Source: NRCAN GHGenius

[12] Source: http://pacificcarbontrust.com/BuyOffsetsfromPCT/tabid/64/Default.aspx

Please also refer to BCUC IR 2.38.2 for a discussion regarding a possible aggregation approach.

Attachment 7.3.1

REFER TO LIVE SPREADSHEET

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Attachment 8.1

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Attachment 10.1

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Attachment 12.1

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Attachment 16.1

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Attachment 20.1

Diane Roy
Director, Regulatory Affairs

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February 4, 2011

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. ("Terasen Gas")

Rate Schedule 16 Pilot Program 2010 Annual Report – British Columbia Utilities Commission (the "Commission") Order No. G-65-09 Compliance Filing

On May 7, 2009, Terasen Gas submitted an application to the Commission, pursuant to sections 59-61 of the *Utilities Commission Act,* for approval of Rate Schedule 16 Interruptible Liquefied Natural Gas ("LNG") Sales and Dispensing Service ("Rate Schedule 16") as a five-year pilot program. The proposed rate structure was a bundled rate service, composed of two charges, a variable charge with a monthly take-or-pay for the liquefaction, storage, and transportation and dispensing of LNG, and a cost of gas or commodity Charge.

On June 4, 2009, the Commission issued Order No. G-65-09 approving Rate Schedule 16 as filed, effective June 15, 2009, as an approximately five-year pilot program, for the period ending December 31, 2014. Pursuant to paragraph 5 of Order No. G-65-09, Terasen Gas was directed to file an annual report including: total number of participants, total contract demand, annual sales volume, annual variable and gas charge revenues, number and duration of Rate Schedule 16 service interruptions, and impacts on the core market supply and any related peaking supply arrangements or purchases.

This submission constitutes Terasen Gas' Rate Schedule 16 Pilot Program Annual Report for the year ending December 31, 2010.

While there continues to be substantial customer interest in innovative uses of liquid natural gas for use in transportation applications as well as in potential applications for remote electrical generation projects, there have not yet been any participants contracted in the Rate Schedule 16 Pilot Program as at the close of business on December 31, 2010. Due to this lack of participation, there is no data to report for the period regarding contract demand, annual sales volume, or annual variable and gas charge revenues. Consequently, there is also no data to report for Rate Schedule 16 service interruptions, impacts on core market supply, or related peaking supply arrangements or purchases as at December 31, 2010.

Terasen Gas believes that the lack of customer take-up for this offering is due to the lack of a LNG refueling service being made available in the province. Rate Schedule 16 allows Terasen Gas to dispense and sell LNG directly from the Tilbury LNG facility, but does not provide any way for that LNG to then reach the vehicles it was intended for. This belief underlies a part of the rationale for Terasen Gas' Application for Approval of General Terms and Conditions for Compressed Natural Gas and Liquefied Natural Gas Service, presently before the Commission.

Terasen Gas anticipates that our first customer for Rate Schedule 16 will be the Vedder Transportation Group ("Vedder") of Abbotsford, BC. In December of 2010, Vedder announced the purchase of 50 LNG powered heavy duty trucks and will, therefore, require a source of approximately 140,000 GJs of LNG per year to fuel them. Terasen Gas is actively negotiating to provide this supply under Rate Schedule 16, supported by a separate agreement for a fueling station and will file any subsequent contract(s) with the Commission as soon as possible.

If you require further information or have any questions regarding this submission, please contact Mark Grist, Manager, Market Development at (604) 592-7874.

Yours very truly,

TERASEN GAS INC.

Original signed:

Diane Roy

Attachment 21.1

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Attachment 30.1

November 13, 2009

Mr. Philip Nakoneshny
Director of Rates and Finance
British Columbia Utilities Commission

RE: Negotiated Settlement Terasen Gas Inc. (TGI) Revenue Requirements Settlement 2010/2011

Dear Mr. Nakoneshny:

On November 5, 2009, TGI forwarded a Draft Agreement and requested that edits and comments be forwarded to TGI. Ministry of Energy, Mines and Petroleum Resources staff have reviewed the Draft Agreement and from a policy perspective, have an interest in 5 items:

11. Energy Efficiency and Conservation ("EEC") Funding for 2010
12. EEC Funding for 2011
13. Alternative Energy Solutions
14. Natural Gas for Vehicles
15. Biogas

Other components of the negotiated settlement such as capital cost structure, interest rates, depreciation rates, salvage values, etc., are outside the purview of the Ministry's interests in this agreement. However, we note that, in the future, Use per Customer Rates (8) and Industrial Demand Forecast (9) may be lower depending on the implementation of TGI's EEC programs.

The 2007 Energy Plan and Climate Action Plan, 2008 amendments to the *Utilities Commission Act,* Ministerial Order B.C. Reg. 326/2008, and the Ministry's involvement in the 2008/09 TGI/TGVI Energy Efficiency and Conservation Application indicate the Province's intent to require electric and natural gas utilities to pursue energy efficiency.

The Ministry is particularly pleased with the reallocation of funds for low income and rental housing programs to $2.4 million for 2010 and 2011. The Ministry also appreciates the increase in industrial energy efficiency program funding in 2011.

.../2

We believe there is great potential for a significant amount of this industrial funding to be applied collaboratively with existing demand side management programs at electric utilities, especially at BC Hydro, in order to minimize duplication of structural costs and to maximize energy savings benefits at industrial facilities.

Appropriate oversight of EEC funding is maintained through the TRC requirements and annual reporting to the Commission. As a result, the Ministry supports Option 12.1 (a) and (b) to maintain program continuity and effectiveness.

Alternative Energy Solutions is a new type of service that TGI proposes to offer to existing and new customers. Geo-exchange, solar-thermal and district energy systems offer the potential to reduce greenhouse gas emissions, and as such, the Ministry is encouraged that TGI is proposing to offer this new type of service.

The Ministry supports the expanded use of natural gas for vehicles (NGV) and biogass, and is encouraged that TGI intends to apply to the Commission for appropriate rates.

Sincerely,

Paul Wieringa
Executive Director
Renewable Energy and Energy Efficiency Branches
Ministry of Energy, Mines and Petroleum Resources
Telephone: 250-952-0243
Facsimile: 250-952-0258

Attachment 35.1

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