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British Columbia Utilities Commission
6th floor, 900 Howe Street
Vancouver, B.C. V6Z 2N3

Attention: Erica M. Hamilton,
Commission Secretary

Dear Sirs/Mesdames:

Re: Terasen Gas Inc.
2011 Revenue Requirements Application for the Fort Nelson Service Area

We enclose the electronic copy of Terasen Gas Inc.'s Final Argument Submissions with respect to the above application.

The requisite hard copies of same will follow by courier.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

[Original signed by Christopher Bystrom]

Christopher Bystrom

CRB/ccm
Encl.

TERASEN GAS INC.

2011 REVENUE REQUIREMENTS APPLICATION
FOR THE FORT NELSON SERVICE AREA

FINAL SUBMISSIONS OF TERASEN GAS INC.

DECEMBER 16, 2010

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A. Introduction

1. These are the Final Argument Submissions of Terasen Gas Inc. ("TGI") with respect to its 2011 Revenue Requirements Application for the Fort Nelson Service Area (the "Application")[1] filed on September 8, 2010. As described in the Application, TGI is seeking an increase in its rates for delivery service to customers on the natural gas distribution system in the Fort Nelson Service Area ("TG Fort Nelson"). Section 10 of the Application describes the specific orders sought by TGI related to the rate increase and the specific rates sought are set out in Table 3 of Exhibit B-5. TGI submits that the evidence in this proceeding demonstrates that the rates sought are just and reasonable and should be approved.

2. These submissions will follow the organization of topics covered in the Application. TGI will address in its reply submissions any issues that may be raised by interveners.

B. Revenue Requirements and Rates

3. The information set out in section 2 of the Application on the revenue requirements for TG Fort Nelson and the rates sought have been updated in Exhibit B-5. Based on the update, the projected revenue deficiency for 2011 is $315,000. The residential delivery rate sought of approximately $2.85 per gigajoule is well below TGI's 2011 rates for the Lower Mainland which are approximately $4.70 per gigajoule.[2]

4. The major factors resulting in the revenue deficiency are summarized on pages 8 and 9 of the Application. The deficiency has been applied evenly to all customers based on the margin (revenue minus cost of gas) at the existing rates and the total deficiency, in accordance with the methodology used since the early 1990s.[3] The Rate Schedule 25 customer is bearing its proportionate share of the rate increase; however, because Rate Schedule 25 is for transportation customers and only includes a delivery charge and not a commodity charge, the percentage increase for this customer class is higher in comparison to the residential and general service rate classes.[4]

5. The Commission has approved a Rate Stabilization Adjustment Mechanism ("RSAM") for TG Fort Nelson, which, similar to the RSAM for other service areas, captures the difference in use per customer due to factors such as colder or warmer temperatures.[5] The RSAM also captures customers served under Rate Schedule 25.[6] TGI believes that this remains appropriate due to the particular, undiversified industrial loads in Fort Nelson as explained in response to BCUC IR 1.2.3.[7] The RSAM rate rider has been calculated as $0.033/GJ (a decrease of $0.004/GJ from the 2010 rider).[8] TGI submits that the RSAM rate rider should be approved as filed.

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1 Exhibit B-1, as updated by the Evidentiary Update filed on November 19, 2010 (Exhibit B-5).

2 Exhibit B-1, page 6; Exhibit B-5, Table 3.

3 Exhibit B-2, BCUC IR 1.4.4.

4 Exhibit B-2, BCUC IR 1.1.3.

5 Commission Order No. G-17-04, Appendix A, pages 2 and 3.

6 Exhibit B-1, page 11 and page 85; Exhibit B-2, BCUC IR 1.1.3.

7 Exhibit B-2. Canfor is the only remaining industrial customer with 2 locations.

8 Please see the calculation in Table 2-4 on page 12 of Exhibit B-1.

C. Gas Sales and Demand and Other Revenue

6. TGI submits its energy and revenue forecasts are reasonable and based on a method which has been approved in the past by the Commission. Section 3 of the Application addresses the forecast of customer additions, energy demand and the resulting revenues and margins forecast for 2011.

7. TGI's customer additions forecast reflects the steady (albeit small) growth in recent years in the residential and commercial sectors. TGI's use per customer rate forecast for Rate 1 and Rate 2.2 reflects the decline over the last several years throughout the province due to efficiency improvements, although Rate 2.2 is forecast to be stable.[9] The demand from the industrial sector is limited to one customer, whose two facilities are now maintaining only heat load consumption.[10] Overall, TGI is forecasting an energy demand decline for TG Fort Nelson.[11]

8. TGI has considered actual numbers to date and does not believe that there is a basis to make an updated forecast.[12] TGI's forecast methodology for residential and commercial customers is on a weather-normalized basis, which is an accepted industry standard and has been approved by the Commission in prior years.[13] The RSAM records the variance between forecast and actual use per customer and distributes or collects the difference to or from customers.[14]

9. As discussed in section 3.6.3 of the Application, TGI is forecasting a decline in revenue in 2011, driven primarily by lower commodity rates.

D. Cost of Gas

10. The cost of gas is a flow through item and TGI is not requesting approval of forecast gas costs in the Application. The current gas cost recovery charge is $5.784 per GJ, as approved by Commission Order No. G-100-10, dated June 10, 2010. This rate will be changing effective January 1, 2011 to $5.015/GJ as approved by Order No. G-190-10 on December 9, 2010.

11. Further information on the cost of gas is provided on page 19 of the Application.

E. Operating and Maintenance Expense

12. TGI submits that its forecast O&M expense for 2011 is required to serve customers and is just and reasonable.

13. As described on pages 20 to 21 of the Application, TG Fort Nelson's gross O&M costs consist of direct costs plus allocated costs from Terasen Gas business units that provide functional support to TG Fort Nelson. From these costs, the overhead capitalized is

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9 Exhibit B-1, pages 16 to 17.

10 Exhibit B-1, page 16. Exhibit B-2, BCUC IR 1.4.2 and 1.7.2.

11 Exhibit B-1, Table 3-4.

12 Exhibit B-2, BCUC IR 2.6.6.3 and 2.7.4. See also the response to BCUC IR 1.2.5, 1.2.6 and 1.2.7 generally.

13 Exhibit B-2, BCUC IR 1.6.1.

14 Exhibit B-2, BCUC IR 1.6.6.3.

subtracted to reach the net O&M. An overhead capitalized rate of 14% was approved as part of the TGI 2010-2011 Revenue Requirements Negotiated Settlement Agreement and TGI submits that the same rate should be used for TG Fort Nelson.[15] As explained on pages 22 to 23 of the Application, the major changes in gross O&M are due to total labour costs, vehicle costs, employee expenses, contractor costs, and facilities.[16]

14. The forecast gross O&M per customer for TG Fort Nelson is forecast to remain flat for 2010 and 2011 at $341 per customer. Taking into account a 2.11% inflation factor for 2011,[17] the forecast 2011 O&M per customer is $7 lower than the 2010 projection.[18]

F. Taxes

15. The tax expenses calculated in the 2011 revenue requirement are described in section 6 of the Application and are reasonable. TGI's forecast property tax for 2011 is explained on pages 25 and 26 and further in response to BCOAPO IR 1.9.1.[19] Overall, property taxes are expected to increase in 2011 compared to 2010 by 5%. TGI's income and other tax expenses are also described in section 6. As described in section 5.2, TGI has included an estimate of HST savings in its 2011 forecast.[20]

16. TGI manages its tax expenses through the tax audit process and various tax planning strategies, as well as ongoing compliance activities.[21] For example, TGI was successful in having the Fort Nelson office classification changed from Utility to Business & Other, which resulted in a lower tax rate being applied.[22]

G. Rate Base

17. TGI submits that its forecast rate base for 2011 is reasonable. The 2011 rate base forecast incorporates required expenditures to meet the expectations of the growing customer base in TG Fort Nelson, make improvements related to system integrity and reliability and ensure that the deferred charges employed are adding value to the customer and the shareholder. Rate base includes the following:

(a) Mid-year net plant in service (gross plant in service, less contributions in aid of construction (CIAC), less accumulated depreciation relating to both), adjusted for the timing of completion of major capital projects;

(b) Work-in-progress not attracting allowance for funds used during construction (AFUDC);

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[15] Commission Order No. G-141-09, dated November 26, 2009.

[16] For further information, please see Exhibit B-3, BCOAPO IR 1.7.

[17] See Exhibit B-3, BCOAPO IR 1.7.8 for source of inflation rate.

[18] Exhibit B-1, page 23. Actual O&M per customer for 2007 to 2009 is provided in Exhibit B-2, BCUC IR 1.8.1. The 2010 projection is higher than 2008 and 2009 actuals, but lower than 2007 actuals. TGI believes gross O&M is the most appropriate comparator since the overheads capitalized rate has changed from 16 to 14%. See Exhibit B-3, BCOAPO IR 1.6.1.

[19] Exhibit B-1 and B-3, respectively.

[20] Exhibit B-1. Also see Exhibit B-3, BCOAPO IR 1.7.1.

[21] Exhibit B-1, page 28.

[22] Exhibit B-3, BCOAPO 1.9.1.

(c) Mid-year balance of unamortized deferred accounts (regulatory assets and liabilities); and

(d) 13 month average of cash working capital and other working capital.

18. These parts of the rate base will be addressed below.

19. The mid-year net plant in service is described in section 7.3 of the Application. As indicated above the calculation of the mid-year net plant in service is: gross plant in service, less CIAC, less accumulated depreciation relating to both. Table 7-2 provides a summary of the gross plant additions. This is then adjusted for the timing of completion of major capital projects. The most significant change in gross plant in service for 2011 is the Muskwa River Crossing Project, which is in the category of Transmission mains. This project will be considered separately in the section below. The other key factors in the mid-year net plant in service calculation are as follows:

(a) Distribution services are forecast to increase due to expenditures required for the replacement of existing services to enable proper filtration and regular equipment testing.[23]

(b) The forecast expenditures for Measuring and Regulating Equipment are attributable to the Muskwa Gate Station Project which is required to maintain the safety, reliability and integrity of the station.[24]

(c) The expenditure in 2010 on Structures and Improvements is needed to replace the Fort Nelson Muster Shop and Storage Building which are at the end of their useful lives.[25]

(d) The CIAC forecast is $1.3 million and unchanged from the 2010 ending balance.

(e) The depreciation rates used for 2011 are those used and approved for the purpose of TGI's Negotiated Settlement Agreement approved by Commission Order No. G-141-09.[26] TGI submits that the same rates should be used for TG Fort Nelson. Consistent with the rates approved for TGI, the depreciation rates for TG Fort Nelson exclude negative salvage.[27]

20. Rate base also includes work-in-Progress not attracting AFUDC, which is forecast to be $38,000 for 2011.[28]

21. The deferred charges in rate base are set out in Table 7-4 of the Application and the total deferred charges in rate base are forecast to be $154,000. Each of the deferral accounts used for TG Fort Nelson is described in section 7.6 of the Application. TGI is requesting approval for continued use of existing deferral accounts which are as follows:

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[23] Exhibit B-1, page 32.

[24] Exhibit B-1, page 32.

[25] Exhibit B-1, page 32; Exhibit B-2, BCUC IR 1.10.

[26] Exhibit B-1, page 41.

[27] Exhibit B-2, BCUC IR 1.16.1.

[28] Exhibit B-1, page 30, Table 7-1.

(a) Gas Cost Reconciliation Account ("GCRA");

(b) RSAM and RSAM interest;

(c) Property Tax Deferral;

(d) Deferred Interest;

(e) 2009 and 2010 ROE and Capital Structure Deferral Account, with full amortization in 2011; and

(f) 2010 IFRS Transitional Deferral.

22. Consistent with past practice, TGI is seeking approval of a 2011 RRA Costs Deferral Account for the costs of the present proceeding.

23. For the purpose of working-capital, TGI proposes to adopt the results of its updated Lead Lag Study which was used in TGI's Negotiated Settlement Agreement approved by Order No. G-141-09.[29] The updated lead lag days are shown in Table 7-7 of the Application.

H. Muskwa River Crossing

24. TGI is requesting acceptance pursuant to section 44.2 of the *Utilities Commission Act* of the Muskwa River Crossing Project based on its updated cost estimate of $3.016 million.[30]

Project Justification

25. Natural gas service to the Fort Nelson area is provided by a single transmission pipeline that crosses the Muskwa River on the southeast side of the town. The pipeline crossing was installed in-stream using an open-cut method in 1974. Surveys in 2008 and 2010 show that approximately 12 metres of pipeline has become exposed and is now at risk of damage from river action. A number of potential scenarios could result in an impact to the pipeline's integrity. Due to river hydrology, it is expected that the section of exposed and unsupported pipe will continue to expand over time further adding to the risk to the pipeline. Eventually the exposed pipe will reach an unsupportable length and the pipe will yield with possible rupture.

26. This pipeline crossing is critical to the delivery of natural gas service to the community of Fort Nelson as loss of the pipeline would completely cut the delivery of natural gas to the community. Consequently, TGI considers the project risk to be high and a "do nothing" option to be unacceptable.[31]

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[29] Exhibit B-1, pages 46 to 47.

[30] Exhibit B-5.

[31] Exhibit B-1, pages 31 to 32; Exhibit B-2, BCUC IR 1.9.1.2, 1.11.1; Exhibit B-5, Chinook Engineering Ltd. Class 3 cost estimate for the IP Bridge Option, page 7 (present asset condition).

Alternatives Analysis

27. TGI has investigated 8 alternatives to remediate or replace the Muskwa River Crossing.[32] The alternatives include 2 horizontal directional drilling (HDD) options, 4 in-stream options, attaching the pipeline to the existing Alaska Highway bridge (the "IP Bridge Option") and constructing a new aerial crossing (the "Aerial Pipeline Option").[33] TGI's alternatives analysis is based on its evaluation of both financial and non-financial factors. TGI's non-financial analysis of the alternatives is presented in Table 1 of Exhibit B-5. The financial analysis is presented in Table 7-3 of the Application, as updated by the Class 3 estimates in Exhibit B-5. TGI has also identified the major risk factors for the options.[34]

28. TGI's project selection process is described in response to BCOAPO IR 2.1.2.[35] As described there, TGI evaluates alternatives using Class 4 cost estimates and develops a Class 3 cost estimate for the preferred alternative. This process is consistent with the Commission's Certificate of Public Convenience and Necessity ("CPCN") Guidelines which require a minimum Class 4 cost estimate for use in the economic comparison of alternatives and a Class 3 estimate for the preferred alternative.[36]

29. TGI initially preferred an HDD peak-to-peak alternative, due its relatively low class 4 cost estimate and non-financial reasons.[37] Accordingly, a Class 3 cost estimate for the HDD crossing option was developed and is included in Appendix A of Exhibit B-5. However, the geotechnical boreholes conducted to refine the cost estimate revealed surficial gravels to significant depths, which means that significant lengths of wash-over casing would be required to conduct the drilling. Based on the new information, the HDD options cost significantly more than previously estimated ($4,087,100 for the peak-to-peak option) and are significantly more risky, with only a 50% chance of success.[38] As a result, TGI would now only pursue an HDD alternative as a last resort.[39] Having effectively ruled out the HDD options, the remaining alternatives consist of the IP Bridge Option, the in-stream options and the Aerial Crossing Option.

30. Based on the currently available information and analysis, the IP Bridge Option is the most cost effective alternative.[40] The IP Bridge has the next highest non-financial rating after the HDD options, takes advantage of existing bridge infrastructure and avoids the environmental risks of an in-stream option.[41] A Class 3 estimate for this option has been developed and is included in Appendix B of Exhibit B-5. The Class 3 cost estimate for

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[32] Exhibit B-5, Table 1. Also see Exhibit B-1, section 7.3.2 to 7.3.2.10 and Appendices A and B.

[33] Exhibit B-1, pages 35 to 39; Exhibit B-5; Exhibit B-8, BCOAPO 2.1.4.

[34] Exhibit B-2, BCUC IR 1.9.2.3.

[35] Exhibit B-8.

[36] British Columbia Utilities Commission, *2010 Certificates of Public Convenience and Necessity Application Guidelines* (Order G-50-10, dated March 18, 2010, Appendix A), at page 6 and 10.

[37] Exhibit B-1, page 38 and 40.

[38] Exhibit B-2, BCUC IR 1.9.2.4.

[39] Exhibit B-7, BCUC IR 2.2.1

[40] See Exhibit B-8, BCOAPO IR 2.1.4 for a summary of the alternatives analysis.

[41] Exhibit B-5, Table 1; Exhibit B-1, Table 7-3, page 38.

the IP Bridge Option is $3,015,650, which is within the range of accuracy of the Class 4 estimate for this option.[42]

31. TGI's submits that based on the current available information, the in-stream options are less cost-effective than the IP Bridge Option. The in-stream alternatives include an open cut option, live line lowering option, concrete matt option and a rip rap placement option.[43] Ultimately, all of the in-stream options are not preferable to the IP Bridge Option due to high environmental risk and the potential for higher costs.[44] This is explained further as follows:

(a) With the exception of the rip rap placement option which has a higher cost estimate, the in-stream alternatives have slightly lower Class 4 cost estimates than the IP Bridge Option.[45] However, all four require further assessment of the extent of the environmental impact.[46] TGI submits that the uncertainty created by the need for further environmental assessment and the lower non-financial ratings as discussed below, outweigh the benefit of the potentially lower cost of three of the in-stream options.

(b) All four in-stream options have lower non-financial ratings than the IP Bridge Option.[47] While the open cut and live line lowering options have the highest non-financial ratings of the in-stream options, each scored a 1 (i.e. "low value, questionable choice") in the category of environment. The rip rap placement option did not score any 1s, but still has a low non-financial rating and a higher class 4 cost estimate than the IP Bridge Option. The concrete mat option did not score any ones, but is overall the lowest rated from a non-financial perspective.

(c) While the open-cut in-stream option has the overall highest non-financial rating of the in-stream options, it presents particular difficulties. Given the size of the Muskwa River, it would be very difficult and environmentally disruptive to install a new crossing using the open cut method. Furthermore, given the environmental disruption and taking into consideration the opinion of TGI's environmental consultant, permits for this option may not be granted unless it could be proven that it was the only technically viable alternative.[48]

(d) The other in-stream options (live line lowering, concrete mats, and rip rap placement) all involve the added complexity of assessing the condition of the existing crossing pipe and coating. Given the flow rate and turbidity of the river, TGI does not believe that it would be possible to make this assessment to a point where the existing crossing pipe could be considered fit for service for the 60 year study period. Furthermore, these options all have the potential for damage

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42 Exhibit B-5, Table 2.

43 These are described on pages 36 to 38 of Exhibit B-1.

44 Exhibit B-8, BCOAPO IR 2.1.4

45 Exhibit B-1, pages 38, Table 7-3.

46 Exhibit B-1, pages 38 to 39.

47 Exhibit B-5, Table 1.

48 Exhibit B-8, BCOAPO IR 2.1.3.

to the pipe during remediation with no obvious means of post construction inspection.[49]

32. The Aerial Pipeline Option would involve the construction of a new aerial crossing over the Muskwa River. The Aerial Pipeline Option is the least preferable alternative from a non-financial perspective and would have high installation and high maintenance costs.[50]

33. TGI therefore submits that the IP Bridge Option is the most effective alternative based on the available information.

Project Risk and Mitigation

34. The primary risk to the IP Bridge Crossing is the necessity to obtain a permit from Public Works and Government Services Canada (PWGSC) to hang the pipe on the underside of the Alaska Highway Bridge over the Muskwa River.[51] The Terasen Utilities have installed gas lines on dozens of bridges owned by the BC Ministry of Transportation and Infrastructure (MOTI) and other bridges in BC. It is possible in most bridge applications to engineer a safe and economical gas pipeline installation that meets Canadian Highway Bridge Design Guidelines. TGI will continue to communicate with PWGSC and will provide an information package in the upcoming month that meets MOTI requirements and that includes a description of the bridges that have gas lines installed on them. TGI will make a formal application to install a new crossing on the bridge in early 2011 with a request for approval by January 28, 2011.[52]

35. A delay in receiving the permit does pose a risk to the project schedule;[53] however, Chinook Engineering Ltd. (the engineering firm that provided the class 3 cost estimate for the IP Bridge Option) estimates that the likelihood that the crossing will be completed in October 2011 is 70% with a P50 confidence interval. Chinook's estimate of the likelihood of the crossing being completed before the end of the 2011 fiscal year is 80% with a P50 confidence interval.[54]

36. Should the IP Bridge Option not be achievable, TGI would advise the Commission of that fact, reconsider all of the remaining crossing options and may investigate any of the remaining options more closely to determine feasibility and preference. When a new recommendation is reached based on the then available information, that recommendation along with the supporting documentation will be provided to the Commission for review and approval on an expedited basis.[55]

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[49] Exhibit B-8, BCOAPO IR 2.1.3.

[50] Exhibit B-5, Table 1; Exhibit B-8, BCOAPO IR 2.1.4.

[51] Exhibit B-7, BCUC IR 2.1.1.1, 2.1.1.2 and 2.1.1.3.

[52] Exhibit B-7, BCUC IR 2.12.1.

[53] Exhibit B-7, BCUC IR 2.1.4.

[54] Exhibit B-7, BCUC IR 2.14.1 and 2.14.2.

[55] Exhibit B-7, BCUC IR 2.1.4.

Energy Objectives, Resource Plan and the Public Interest

37. Section 44.2(5) of the *Utilities Commission Act* specifies certain factors that the Commission must consider when considering whether to accept an expenditure schedule. TGI submits the following:

(a) The Project does nothing to hamper British Columbia's energy objectives, as it serves to maintain infrastructure to meet future needs;

(b) The Project is consistent with the Terasen Utilities' 2010 Long-term Resource Plan, and was also included in Appendix D-4 of that Plan;

(c) Sections 6 and 19 of the *Clean Energy Act* do not apply to the Project;

(d) Consideration of demand side measures are not relevant to the Project; and

(e) The Project is in the best interests of Fort Nelson customers who receive service from Terasen Gas. As described above, the Muskwa pipeline crossing is critical to the delivery of natural gas service to the community of Fort Nelson as loss of the pipeline would completely cut the delivery of natural gas to the community. Consequently, TGI considers the project risk to be high and a "do nothing" option to be unacceptable.[56]

Conclusion

38. TGI submits that the evidence demonstrates that the Muskwa River Crossing Project is required to serve customers and that the IP Bridge Option is the most cost-effective alternative. TGI has prepared a Class 3 cost estimate for the IP Bridge Option in accordance with the CPCN Guidelines. TGI is therefore requesting the Commission accept the Muskwa River Crossing Project pursuant to section 44.2(3) of the *Utilities Commission Act*.

39. TGI is also requesting that the capital costs of $3.016 million (before AFUDC) for the Muskwa River Crossing Project be included in rate base for the purpose of calculating 2011 rates, as described in section 7 of the Application. The Muskwa River Crossing Project, however, is not scheduled to enter rate base until its projected in-service date in October 2011, which is taken into account in the rate base calculation.[57] Consequently, the rate in 2011 is not as sensitive to project costs as it would be if the project were to be in-service and enter rate base earlier in the year. When the Commission sets rates for 2012, TGI will have an even more certain cost estimate for the project and for 2013 and beyond the rates should be based on the actual costs of the project.[58]

I. Financing and Capital Structure

40. TG Fort Nelson shares the same debt and equity percentage (60% and 40%, respectively) as the other three Terasen Gas service Areas as approved by Commission

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[56] Exhibit B-1, pages 31 to 32; Exhibit B-2, BCUC IR 1.9.1.2, 1.11.1; Exhibit B-5, Chinook Engineering Ltd. Class 3 cost estimate for the IP Bridge Option, page 7 (present asset condition).

[57] See explanation of the 13-Month Adjustment on page 42 of Exhibit B-1.

[58] Exhibit B-7, BCUC IR 2.1.1.5 and 2.1.4.

Order No. G-158-09. The amounts of long-term and unfunded debt for TG Fort Nelson are an allocation from TGI and were approved as part of the TGI 2010-2011 Revenue Requirements Negotiated Settlement Agreement.[59]

J. Conclusion

41. TGI submits that based on the evidence in this proceeding the Muskwa River Crossing Project is in the public interest and should be accepted and that the rates sought for TG Fort Nelson for 2011 are just and reasonable and should be approved as filed.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

Dated: December 16, 2010 *original signed by*

Chris Bystrom
Counsel for Terasen Gas Inc.

[59] Exhibit B-1, page 48.