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September 8, 2010

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. - Fort Nelson Service Area (TG Fort Nelson)

2011 Revenue Requirements Application for Changes to the Revenue Stabilization Adjustment Mechanism ("RSAM") Rate Rider and Delivery Rates effective January 1, 2011

Pursuant to Sections 58, 60 and 61 of the *Utilities Commission Act* (the "Act"), attached please find the TG Fort Nelson application for approval of its 2011 Revenue Requirements and changes to the RSAM rate rider and delivery rates effective January 1, 2011 on a permanent basis.

If you have any questions related to this filing, please contact the undersigned or Diane Roy at (604) 576-7349.

Yours very truly,

TERASEN GAS INC.

Original signed by: Diane Roy

For: Tom A. Loski

Attachments

TERASEN GAS INC.

FORT NELSON SERVICE AREA

2011 Revenue Requirements and Rates

Volume 1 - Application

September 8, 2010

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1 INTRODUCTION, EXECUTIVE SUMMARY AND BACKGROUND

1.1 Introduction

Terasen Gas Inc. ("Terasen Gas" or the "Company") 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") to reflect increases in its revenue requirements of 6.4 per cent (Section 9, Schedule 1.0, Line 25) of total revenues, effective January 1, 2011 (the "2011 Revenue Requirements and Rates Application" or the "Application"). This increase is required to ensure that the Company's rates recover the costs of serving its customers. The rate increases, proposed in this Application for which approval is sought, represent an increase of approximately 6.1 per cent in rates (Section 9, Schedule 9.0, Line 11) for residential and commercial customers (customers served under Rate Schedules 1, 2.1, and 2.2). The proposed increase for the customer served under Rate Schedule 25 is an increase of approximately 20.4 per cent (Section 9, Schedule 1.0, Line 24), equal to the proposed increase in the delivery margin.

This 2011 Revenue Requirements and Rates Application include a detailed discussion of the components influencing the need for a revenue requirement increase for 2011. In support of the Application, Terasen Gas has provided discussion of the business drivers, capital expenditures and operating and maintenance requirements of TG Fort Nelson for 2011. Terasen Gas has continued to provide safe, reliable and efficient service to Fort Nelson customers during its term of ownership.

1.2 Executive Summary

The requirement for an increase in revenues is determined by various business drivers including capital expenditures, projected customer use rates, volumes and revenues, and operating and maintenance expenses. Detailed support material has been provided in Sections 2 through 9 which show the impact of these business drivers on the TG Fort Nelson revenue requirements for 2011.

Overall, TG Fort Nelson has experienced an increase in revenue requirements of $295 thousand:

- Forty per cent of the increase is due to a higher approved equity ratio for 2010 and 2011 and higher approved return on equity beginning July 1, 2009;
- Approximately one quarter of the increase is due to changes to depreciation rates; and
- The remainder of the increase is mainly due to rate base growth driven by recent capital projects, including the Muskwa River Crossing.

Operations in Fort Nelson consist of a transmission lateral from the nearby Spectra Energy processing plant to the town of Fort Nelson together with a gas distribution system. Also included in the service area is the distribution system in Prophet River.

TG Fort Nelson's gas supply has typically been obtained through one contract. For the past number of years, the Company has used a small portion of its contracted gas storage capacity at Aitken Creek to improve the load factor of the Fort Nelson load and to mitigate the impact of gas volatility for Fort Nelson customers. The diversity of Terasen Gas' overall gas supply portfolio has assisted over the years in providing favourable gas supply arrangements for TG Fort Nelson.

Gas cost recoveries within rates are based on forecast costs. Potential rate changes for the cost of gas are reviewed by the Commission on a quarterly basis and gas costs are passed on to customers without mark-up. The actual costs invariably differ from the forecast costs. Terasen Gas, consistent with past practice, will continue to defer any difference for TG Fort Nelson between the costs incurred to purchase the gas commodity and the gas cost recoveries collected through rates in the Gas Cost Reconciliation Account ("GCRA").

Customers in TG Fort Nelson continue to benefit in various ways from being part of a much larger gas distribution company. Some of these benefits include:

- Access to the necessary resources, expertise and training in all areas affecting gas distribution utilities;
- Access to low cost capital funding;
- Access to the buying power of a larger company, reducing the costs of pipe and other materials and supplies; and
- Access to the commodity-related benefits of being in a company that is a large regional buyer of natural gas and a significant holder of various natural gas storage, transportation, peaking and other gas supply arrangements designed to mitigate and optimize gas supply costs.

The costs included in this Application are for the most part consistent with past history and trends. TG Fort Nelson has appropriately reflected the accounting and other policy changes in this Application that have been approved for the Lower Mainland, Inland, and Columbia service territories of Terasen Gas Inc. as part of the Negotiated Settlement for 2010-2011 Revenue Requirements and Rates. Significant capital expenditures are required in the Fort Nelson service area to ensure the continued integrity and reliability of the distribution system, and the ongoing safety of customers and employees. An upgrade to the Fort Nelson Odorizer Station was previously approved by Commission Order No. G-172-08. In addition, in 2010 an upgrade to the Muskwa Gate Station was required to maintain the safety, integrity and reliability of that asset. As part of this Application, TG Fort Nelson is requesting approval for the replacement of the Muskwa River Crossing, described further in the following paragraphs.

In 2008, a scheduled survey of the existing 6" underwater Transmission pipeline crossing of the Muskwa River serving Fort Nelson was completed. The survey noted that part of the pipeline, as a result of river scour and bank erosion, was now exposed and subject to potential damage from river action.

Based on an engineering assessment and other work completed to date, TG Fort Nelson considers that a pipeline replacement using Horizontal Directional Drilling ("HDD") methodology will likely be the most cost-effective strategy. The status of the HDD evaluation and other potential alternatives are discussed in Section 7.3.2 of this Application. TG Fort Nelson is targeting an expected completion date of the project in late 2011. Project costs for the HDD option are currently estimated to be $2.45 million (excluding Allowance for Funds Used During Construction ("AFUDC")).

Either the unsuitability of an HDD crossing, or a change in conditions related to the HDD crossing could result in an estimate above the $2.45 million, or another alternative being more cost-effective. When a final alternative is selected and a final Class 3 cost estimate is completed, TG Fort Nelson will file an Evidentiary Update at that time. If the final estimate is materially different than the amount included in the Application, then depending on the timing of completion of that estimate, TG Fort Nelson will either request updated 2011 rates or propose regulatory treatment of the difference at that time. When TG Fort Nelson applies for 2012 rates, it will include its best estimate of the costs of the Muskwa River Crossing Project at that time, based on actuals to date and an estimate of any remaining expenditures.

The Company believes that the approvals sought in this Application appropriately accommodate the costs of serving the Fort Nelson customers, and the required capital improvements to continue that service. The proposed rates are fair and reasonable, allowing the Company to recover its prudently incurred costs in providing efficient and effective natural gas service to customers.

1.3 Organization of this Application

Section 1 Introduction, Executive Summary, and Background - discusses in summary the Revenue Requirement Application, Terasen Gas and TG Fort Nelson background including operations and historical revenue requirement changes.

Section 2 Revenue Requirement and Rates – discusses the revenue requirement and the proposed rates the Company is requesting.

Section 3 Gas Sales and Demand and Other Revenue – discusses the impact of use rates, customer additions and other factors affecting demand, revenue and margin in the Fort Nelson region.

Section 4 Cost of Gas – discusses the impact of gas costs on total revenue requirement changes.

Section 5 Operating and Maintenance ("O&M") Expenses

Section 6 Taxes – discusses Property Tax, Income Tax, and Other Taxes

Section 7 Rate Base and Capital Expenditures – discusses rate base overall, as well as each of its components including plant additions, deferral accounts and working capital.

Section 8 Financing and Capital Structure

Section 9 Financial Schedules

Section 10 Approvals Sought and Proposed Regulatory Process

Section 11 Glossary of Terms

1.4 Background and Recent Regulatory Context

This section outlines the corporate history of Terasen Gas and TG Fort Nelson, followed by the applicable regulatory context.

1.4.1 HISTORY OF TERASEN GAS

Terasen Gas is one of the largest natural gas distribution companies in Canada, based on the number of customers and service area. Terasen Gas, through its parent company Terasen Inc., is a wholly owned subsidiary of Fortis Inc., the largest investor-owned distribution utility in Canada.

Terasen Gas is responsible for the procurement and supply of natural gas to the majority of its customers. For customers in all of its service areas, the Company purchases its supply of gas from a number of producers, aggregators and marketers. Terasen Gas also contracts with various providers for service on upstream pipelines, capacity in underground storage facilities and various types of peaking and gas supply cost mitigation arrangements.

The gas supply, transmission and distribution functions of Terasen Gas have always focused on activities that are integral to the safe, reliable and efficient running of utility operations. In addition to transmission and distribution system construction, installation and operation and emergency response, there are a number of key support functions, including planning and designing facilities, corrosion control, metering, meter reading, leak surveying, right of way management and materials management and distribution.

Also important are the systems and services that allow Terasen Gas to meet its responsibilities effectively in today's dynamic business environment. These supporting systems include customer billing and customer care, marketing, information technology, municipal, community and aboriginal relations, legal, risk management, environment, health and safety, regulatory, human resources and finance/accounting.

1.4.2 TG FORT NELSON BACKGROUND

The natural gas distribution system in the Fort Nelson area was acquired in 1985 through the acquisition of Fort Nelson Gas Ltd. by Inland Natural Gas Co. Ltd. Fort Nelson Gas Ltd. was amalgamated in 1989 with Inland Natural Gas and other companies and continued as BC Gas Inc., later BC Gas Utility Ltd. and now Terasen Gas Inc.

Rates have been set separately for TG Fort Nelson from the date the company was acquired to the present. Terasen Gas (formerly BC Gas Utility Ltd.) sought regulatory consolidation of TG Fort Nelson with the remainder of the Company in its 1992 Revenue Requirement Application, but the application was not approved. Since then, TG Fort Nelson has been excluded from the Company's general revenue requirement applications and Performance Based Ratemaking plans.

1.4.3 REGULATORY BACKGROUND

The most recent revenue requirement change approved by the Commission was on November 20, 2008 by Order No. G-172-08. In that Order, the Commission approved an increase in rates for TG Fort Nelson effective January 1, 2009 to recover a revenue deficiency of $372 thousand primarily due to a decline in industrial demand and use rates per customer.

Prior to the 2009 rate increase, a revenue requirement change affecting the rates for delivery service in Fort Nelson was an increase of $265 thousand approved by the Commission by Order No. G-27-08. That revenue requirement change was primarily attributed to the downturn of the forest industry affecting the industrial demand for the Fort Nelson region.

In addition, on December 3, 2009 by Order No. G-147-09, the Commission approved the creation of two new deferral accounts along with the continuation of existing deferral accounts, changes to the RSAM rate rider, and continuation in 2010 of the approved 2009 rates effective January 1, 2010. These requests were driven primarily by changes to TG Fort Nelson's return on equity and capital structure, and the proposed adoption by Terasen Gas of updated depreciation expenses and overheads capitalized rate.

1.5 Approvals Sought and Proposed Regulatory Process

Section 10 of this Application specifies the various requests for which the Company is seeking Commission approval. TG Fort Nelson also sets out in Section 10 a proposed regulatory process and timeline for the review of this Application. TG Fort Nelson believes that a written hearing process is the most appropriate method for the review of this Application. The

Company's objective with its proposed regulatory process and timetable is an efficient review and approval process for all parties concerned.

If the Commission is not able to issue a Decision on this Application by December 20, 2010, TG Fort Nelson is seeking interim rates, effective January 1, 2011 as requested in this Application.

1.6 Conclusion

Terasen Gas has performed efficiently and effectively over many years in delivering value to its TG Fort Nelson customers. The Residential delivery rates requested in this Application of approximately $2.75 per Gigajoule are well below those of Terasen Gas 2011 rates of approximately $4.70 per Gigajoule. The increase in rates being sought by the Company, effective January 1, 2011, is reasonable and is necessary to cover the cost of service to the customers in the TG Fort Nelson area.

2 REVENUE REQUIREMENTS AND RATES

2.1 Introduction

The purpose of this section is to provide an overview of the total revenue requirement and rates for the forecast period of 2011. The supporting discussion can be found in Sections 2 through 8, with financial schedules provided in Section 9 and the specific approvals requested in Section 10.

The Company's revenue requirement reflects all of the inputs in Sections 2 through 8, and the financial schedules. The revenue requirement increase that TG Fort Nelson is requesting is based on sound research and forecasting, utilizing our knowledge and experience to determine what we believe is the likely course of events over the upcoming forecast period 2011.

We have determined the Company's revenue requirement to be $4.92 million (Section 9, Schedule 10.1, Line 21) in 2011. This results in an approximate 6.4 per cent (Section 9, Schedule 10.1, Line 25) increase in bundled rates.

2.2 Revenue Deficiency

For 2011, TG Fort Nelson is forecasting a total revenue deficiency of $295 thousand (Section 9, Schedule 1.0, Line 21). As displayed in Table 2-1 below, the largest contributors to the revenue deficiency are depreciation & amortization, return on equity, operating & maintenance expense, income tax, and interest expense, favourably offset by decreases in other revenue and property tax.

Table 2-1: TG Fort Nelson Revenue Deficiency in 2011 Driven by Higher Rate Base and Return (amounts in $ thousands)

Description	2009 Decision	2011 Forecast @ Existing Rates	Difference
(1)	(2)	(3)	(4)
	a	b	c = b - a
Revenue			
Residential/Commercial	$ 5,854	$ 4,519	$ (1,335)
Transportation Service	41	108	67
Total Revenue:	**5,895**	**4,626**	**(1,269)**
Less:			
Cost of Gas	4,476	3,179	(1,297)
Gross Margin:	**1,419**	**1,448**	**29**
Cost of Service (excl. COG)			
O&M	664	698	35
Property Tax	158	165	7
Depreciation	185	284	99
Amortization	6	71	66
Income Tax	59	83	24
Interest Expense	232	251	19
Other Revenue	(45)	(60)	(15)
Return on Equity	160	250	90
Total Cost of Service:	**1,419**	**1,743**	**324**
Surplus/(Deficiency):	**$ 0**	**$ (295)**	**$ (295)**
Revenue Deficiency (Surplus) as a % of Gross Margin			**20.37%**
Revenue Deficiency (Surplus) as a % of Total Revenue			**6.37%**

A summary of the major factors affecting the deficiency follows.

The increase in margin is driven by growth in customers, as discussed in Section 3.

Increased operating and maintenance expense is mainly due to a change in the overhead capitalized rate, decreasing from 16% in 2009 Decision to 14% for 2011 forecast, combined with inflationary effects on labour. More information can be found in Section 5.

Depreciation expense increased by $99 thousand as a result of higher depreciation rates (rate changes provided in Section 7), as approved for Terasen Gas in Commission Order No. G-142-09, as well as growth in capital since 2009.

Increased amortization expenses of $66 thousand in 2011 are primarily due to the amortization of the 2009 and 2010 ROE and Capital Structure deferral account, described more fully in Section 7.

Income tax expense increased by $24 thousand in 2011 as a result of higher earned return and depreciation & amortization, partially offset by lower income tax rates (from 30.0% in 2009 to 26.5% in 2011). Please refer to Section 6 for more information.

An increase in interest expense of $19 thousand in 2011 is the result of the higher rate base partly offset by a lower debt rate as further discussed in Section 8.

The decrease in other revenue of $15 thousand is mainly attributed to higher late payment charges ($11 thousand) and revenue from service work ($3 thousand). More information is provided in Section 3.

As compared to the 2009 Decision, the increase in return on equity is largely due to the increase in rate base as a result of the Muskwa River Crossing project and other integrity-related capital additions in 2010. The rate base has increased from $5.4 million (2009 Decision) to $6.6 million in 2011 (Section 9, Schedule 2, Line 30). The increase in the equity portion of rate base (from 35.01% in 2009 to 40.00% in 2011) and higher ROE (from 8.47% in 2009 to 9.50% in 2011), both as approved in Commission Decision No. G-158-09, have increased the deficiency. More information is provided in Section 8 and Section 9 Schedule 15.5.

2.3 Rates

Table 2-2 below shows the progression from the bundled Sales and Transportation Service rates for 2010 to the rates applied for effective January 1, 2011 for customers served under Rate Schedules 1, 2.1, 2.2, and 25. TG Fort Nelson provides service to all its customers under these rate schedules. The rate increases proposed for residential and commercial customers represent an overall increase of 6.1 per cent (Section 9, Schedule 9.0, Line 11) over existing rates. The proposed increase for customers served under Rate Schedule 25 is 20.4 per cent (Section 9, Schedule 1.0, Line 24).

Table 2-2: Proposed Tariff Rate Change and Rate Class Revenue Recovery

Particulars	Tariff @ 2010 Rates	Less: Delivery Rate Rebate (in $/GJ)	Less: RSAM Recovery Charge (in $/GJ)	Less: Average Cost of Gas	Delivery Margin	Margin Rate Increase	Add: Average Cost of Gas	Add: Revised RSAM Recovery Charge	Tariff @ Revised Rates Jan 1/11
Residential									
1st Blk ≤ 2 GJ $ / Month	$ 19.296	$ -	$ (0.070)	$ (11.570)	$ 7.656	$ 1.730	$ 11.570	$ -	$ 20.956
2nd Blk Next 28 GJ $ / GJ	$ 7.784	$ -	$ (0.037)	$ (5.784)	$ 1.963	$ 0.383	$ 5.784	$ -	$ 8.130
3rd Blk Excess of 30 GJ $ / GJ	$ 7.726	$ -	$ (0.037)	$ (5.784)	$ 1.905	$ 0.372	$ 5.784	$ -	$ 8.061
General Service - Small Commercial									
1st Blk ≤ 2 GJ $ / Month	$ 34.336	$ -	$ (0.070)	$ (11.570)	$ 22.696	$ 4.938	$ 11.570	$ -	$ 39.204
2nd Blk Next 298 GJ $ / GJ	$ 8.016	$ -	$ (0.037)	$ (5.784)	$ 2.195	$ 0.447	$ 5.784	$ -	$ 8.426
3rd Blk Excess of 300 GJ $ / GJ	$ 7.945	$ -	$ (0.037)	$ (5.784)	$ 2.124	$ 0.433	$ 5.784	$ -	$ 8.341
General Service - Large Commercial									
1st Blk ≤ 2 GJ $ / Month	$ 34.336	$ -	$ (0.070)	$ (11.570)	$ 22.696	$ 4.938	$ 11.570	$ -	$ 39.204
2nd Blk Next 298 GJ $ / GJ	$ 8.016	$ -	$ (0.037)	$ (5.784)	$ 2.195	$ 0.447	$ 5.784	$ -	$ 8.426
3rd Blk Excess of 300 GJ $ / GJ	$ 7.945	$ -	$ (0.037)	$ (5.784)	$ 2.124	$ 0.433	$ 5.784	$ -	$ 8.341
Transportation Service									
1st Blk ≤ 20 GJ $ / GJ	$ 2.319	$ -	$ -	$ (0.113)	$ 2.206	$ 0.554	$ 0.113		$ 2.873
2nd Blk Next 260 GJ $ / GJ	$ 2.145	$ -	$ -	$ (0.113)	$ 2.032	$ 0.511	$ 0.113		$ 2.656
3rd Blk Excess of 280 GJ $ / GJ	$ 1.736	$ -	$ -	$ (0.113)	$ 1.623	$ 0.410	$ 0.113		$ 2.146
Minimum Delivery Charge per Month	$ 1,458.00				$ 1,458.00	$ 348.00			$ 1,806.00
Administration Charge	$ 202.00	$ -	$ -		$ 202.00	$ -			$ 202.00
RSAM Recovery Charge	$ 0.037	$ -	$ (0.037)	$ -	$ -		$ -	$ -	$ -

TG Fort Nelson does not have any customers served under Rate Schedules 2.3, 2.4, 3.1, 3.2 and 3.3. The Company proposes to increase the delivery component of the rates by the general margin percentage increase of 20.4 per cent (Section 9, Schedule 1.0, Line 24), except for customers served under Rate Schedule 2.4 which has no specified rate for NGV compression/dispensing service. The permanent proposed rate changes and rates effective January 1, 2011 for these rate classes are shown below in Table 2-3.

Table 2-3: Proposed Tariff Rate Change & Rate Class Revenue Recovery

Particulars	Tariff @ 2010 Rates	Less: RSAM Recovery Charge	Less: Average Cost of Gas	Delivery Margin	Margin Rate Increase	Add: Average Cost of Gas	Add: Revised RSAM Recovery Charge	Tariff @ Revised Rates Jan 1/11
					23.9%			
Rate Class 2.3 - Natural Gas Vehicle Fuel Service								
1st Blk ≤ 2 GJ $ / Month	$ 33.99	$ -	$ (11.57)	$ 22.42	$ 5.35	$ 11.57	$ -	$ 39.34
2nd Blk Next 298 GJ $ / GJ	$ 8.539	$ -	$ (5.784)	$ 2.755	$ 0.658	$ 5.784	$ -	$ 9.197
3rd Blk Excess of 300 GJ $ / GJ	$ 8.469	$ -	$ (5.784)	$ 2.685	$ 0.641	$ 5.784	$ -	$ 9.110
Rate Class 3.1 / 3.2 - Industrial Service < 360,000 GJ per Year								
Delivery Charge								
1st Blk ≤ 20 GJ $ / GJ	$ 2.319	$ -	$ -	$ 2.319	$ 0.554	$ -		$ 2.873
2nd Blk Next 260 GJ $ / GJ	$ 2.145	$ -	$ -	$ 2.145	$ 0.511	$ -		$ 2.656
3rd Blk Excess of 280 GJ $ / GJ	$ 1.736	$ -	$ -	$ 1.736	$ 0.410	$ -		$ 2.146
Minimum Month Delivery Charge	$ 1,458.00			$ 1,458.00	$ 348.00			$ 1,806.00
Gas Cost Recovery Charge	$ 5.784		$ (5.784)	$ -	$ -	$ 5.784		$ 5.784
RSAM Rate Rider	$ 0.037	$ (0.037)		$ -	$ -	$ -	$ -	$ -
Rate Class 3.3 - Industrial Service ≥ 360,000 GJ per Year								
Delivery Charge								
1st Blk ≤ 20 GJ $ / GJ	$ 2.319	$ -	$ -	$ 2.319	$ 0.554	$ -		$ 2.873
2nd Blk Next 260 GJ $ / GJ	$ 2.145	$ -	$ -	$ 2.145	$ 0.511	$ -		$ 2.656
3rd Blk Excess of 280 GJ $ / GJ	$ 1.736	$ -	$ -	$ 1.736	$ 0.410	$ -		$ 2.146
Minimum Month Delivery Charge	$ 1,458.00			$ 1,458.00	$ 348.00			$ 1,806.00
Gas Cost Recovery Charge	$ 5.784		$ (5.784)	$ -		$ 5.784		$ 5.784
RSAM Rate Rider	$ 0.037	$ (0.037)		$ -		$ -	$ -	$ -

2.3.1 RSAM

In its 2004 Revenue Requirements Application, Terasen Gas sought approval from the Commission to implement a Revenue Stabilization Adjustment Mechanism ("RSAM") account for TG Fort Nelson to capture variations in the delivery margin for residential, commercial and industrial rate classes. Commission Order No. G-17-04, dated February 5, 2004, granted approval for the implementation of the RSAM account. An RSAM deferral account accumulates the annual RSAM debits and credits with one third of the net balance being recovered or refunded in the following year via a positive or negative rate rider.

The RSAM for TG Fort Nelson differs from the RSAM of the other regions of Terasen Gas in that it includes the customers served under Rate Schedule 25. The RSAM for TG Fort Nelson customers served under Rate Schedule 25 is based on forecast delivery volumes minus actual delivery volumes multiplied by the delivery rate. The rationale for requesting the inclusion of customers served under Rate Schedule 25 in the TG Fort Nelson RSAM pertains to the specific local circumstances in TG Fort Nelson relative to the rest of the Terasen Gas system. First, the margin from customers served under Rate Schedule 25 comprises approximately 7% (based on the 2011 forecast) of the total forecast delivery margin in TG Fort Nelson. Second, the TG Fort Nelson margin collection from customers served under Rate Schedule 25 is entirely volumetric except for the monthly administrative fee. In the other service areas of the Company, a considerable percentage of the charges for delivery service in the industrial classes are on a fixed basis, making use of demand charges and other fixed rate tariffs. A third consideration is the lack of diversity in the energy demand of the customers served under Rate Schedule 25 in TG Fort Nelson (historically forestry sector), making margin collection more volatile as it is subject to the variations of a single industry that is cyclical. In the rest of the Terasen Gas system, there are various industries and services represented as well as a large number of customers.

The RSAM rate rider for 2011 has been calculated as $0.033/GJ (a decrease of $0.004/GJ from the 2010 rider) as set out in Table 2-4 below.

Table 2-4: Calculation of Rider 5 RSAM for 2011

Particulars	$000s	Volumes	RSAM Unit Rider ($/GJ)
(1)	(2)	(3)	(4)
RSAM (Rider 5) Calculation			
Projected ending 2010 RSAM Deferral Balance (including interest) net-of-tax	$ 42,954		
Amortization over three years (Commission Order No.G-17-04) net-of-tax	$ 14,318		
Amortization over three years (Commission Order No.G-17-04) pre-tax = Net-of-tax amortization /(1-tax rate)	**$ 19,480**		
Total Forecast Volumes for 2011 (TJ:			
Rate 1 - Residential		263.4	$ 0.033
Rate 2.1 - Small Commercial		190.8	$ 0.033
Rate 2.2 - Large Commercial		94.4	$ 0.033
Rate 3.1 - Industrial Service		0.0	$ 0.033
Rate 3.2 - Industrial Service		0.0	$ 0.033
Rate 3.3 - Industrial Service		0.0	$ 0.033
Rate 25 - Large Commercial Transportation		49.5	$ 0.033
		598.1	$ 0.033
		RSAM Rider for 2011	**$0.033**
		Approved Rider for 2010 (BCUC Order G-147-09 / G-158-09)	**$0.037**
		Rider 5 Increase/(Decrease)	**($0.004)**

2.4 Summary

The company's revenue requirement & rates reflects all of the inputs in the financial schedules, and takes into consideration all of the impacts described in this Application. The revenue requirement increase of $295 thousand in 2011 (Section 9, Schedule 1.0, Line 21) is based on sound research and forecasting, using our knowledge and experience to determine the most likely course of events over the forecast period.

3 GAS SALES AND DEMAND AND OTHER REVENUE

3.1 Introduction

This section addresses the forecast of customer additions, energy demand and the resulting revenues and margins for 2011. Included is a review of the energy forecast methodology, as well as factors influencing customer additions and customer use rates.

A combination of the consumption history, sector analysis and informal discussion with management from the industrial customers has provided the basis for the forecast volumes. Similarly, revenue and margin forecasts reflect the most recently approved rates.

3.2 Forecast Methodology

Consistent with the forecasting process followed by Terasen Gas for its other three service areas (Lower Mainland, Inland and Columbia), the forecasting process is comprised of three main components:

- Customer additions (account) forecast;
- Average use per customer forecast; and
- Industrial Forecast.

The residential and commercial energy forecast, consisting of customers served under Rate Schedules 1, 2.1, and 2.2, is driven by the respective account and use per customer forecasts, while the industrial energy forecast incorporates the remaining customer under Rate Schedule 25.

The customer additions forecast reflects prevailing macroeconomic circumstances affecting residential and commercial customers. The industrial forecast includes only the single remaining customer, with two locations served under Rate Schedule 25.

Consistent with the methodology used across the other service areas for Terasen Gas, the average use per customer is estimated for customers served under Rate Schedules 1, 2.1, and 2.2 and then is multiplied by the corresponding forecast of customers in each rate class to derive energy consumption. The industrial forecast continues to rely on historical data and sector analysis.

Current approved rates are applied against the energy forecast to calculate the revenue forecast. The underlying assumptions and components of that forecast are discussed below.

3.3 Underlying Assumptions

The following assumptions were made about external influences when developing this forecast:

- Population remains relatively stable, but growing at lower levels than have been experienced most recently. Continued challenges faced by the forestry industry affect the short term population growth, with increased activity in the oil and gas sector offsetting the longer-term impacts; and
- Natural gas commodity prices remain relatively stable over the short term – market prices are depressed due to weakened industrial demand, steady production levels and healthy US storage balances.

The latest population projection from BC Statistics shows an expected 1.0% increase in population for the TG Fort Nelson region from 2010 to 2011[1]. This is lower than previous estimated growth rates (the expected growth from 2008 to 2009 was 1.7%). Although BC Statistics does not provide details on the basis for the specific changes in growth rates, there are two major factors assumed to be influencing growth in the region.

First, the challenges faced by the forestry industry continue to be affected by the decimated U.S. housing market and subsequent drop in demand for forest products, which is influencing customer growth.

Second, there exist opportunities in the oil and gas sector, which somewhat offset the decline in forestry The unconventional shale gas deposits in the Horn River Basin have captured the interest and investment of 11 major exploration companies. Since Fort Nelson is well positioned to service this industry, the region is expected to see increased growth over the long term. Given these factors, it is not unreasonable to assume customer additions will remain relatively stable over the forecast period.

With respect to industrial firms that use natural gas in Fort Nelson, there remains only one customer with two locations served under Rate Schedule 25 that accounts for approximately 7% of the TG Fort Nelson demand in 2011. For the purpose of determining rates in 2011, the assumption is that the remaining single customer served under Rate Schedule 25, Canfor, will continue to maintain heating load consumption for its two facilities.

3.4 Customer Additions

The customer additions forecast is derived from long-term provincial forecasts of household formations at the community level and validated against the Canada Mortgage and Housing Corporation's ("CMHC") nearer term forecasts in order to reflect the most current market

[1] Appendix C: Household Formations Data from BC Stats – P.E.O.P.L.E 34

situation. In addition, input from the Fort Nelson regional manager has provided information consistent with those from the forecast. The forecast of customer additions is applied to both residential and commercial rate classes while no growth is assumed for industrial customers. The latest available economic analyses from the B.C. Government, major banks and other organizations are reviewed for consistency with the overall trend in household formations.

Table 3-1 below provides a summary of the residential, commercial and industrial year-end net customer additions since 2007. Table 3-1 presents actual values for 2007 through to 2009. The 2010 projection for year-end includes actual values up to March 31, 2010. The 2011 values represent the forecast.

Table 3-1: Annual Customer Additions Show Stable Growth

	2007	2008	2009	2010	2011
	Normal	**Normal**	**Normal**	**Projection**	**Forecast**
Rate 1	7	-13	10	10	10
Rate 2.1	6	2	2	3	2
Rate 2.2	1	-2	0	0	0
Rate 25	0	0	0	0	0
Total	**14**	**-13**	**12**	**13**	**12**

Fort Nelson has experienced variations in the rate of customer additions due to the dynamics of the energy and forestry industries. The total number of customers has been growing within the residential and commercial rate classes as seen below in Table 3-2. New construction has been at a low and also uncertain, particularly with the mixed decisions on whether to go forward with new projects such as condominiums, native reserve projects and residential housing. The completion of a new recreation centre and completion of new construction will attract a higher population growth. However, the growth won't be evident until late 2011.

Table 3-2: Year-end Customers Show Stable Growth in Recent Years

	2007	2008	2009	2010	2011
	Normal	**Normal**	**Normal**	**Projection**	**Forecast**
Rate 1	1,928	1,915	1,925	1,935	1,945
Rate 2.1	408	410	412	415	417
Rate 2.2	30	28	28	28	28
Rate 25	2	2	2	2	2
Total	**2,368**	**2,355**	**2,367**	**2,380**	**2,392**

The monthly forecast of customers embedded in the year-end forecast is applied to the monthly use per customer forecast to calculate the annual volumes.

3.5 Use per Customer (Residential and Commercial Customers)

Individual use per customer projections are developed for each rate class by considering the following factors:

- Recent historical weather-normalized use per account;
- Efficiency improvements – appliance and insulation upgrades.

The decline in residential use rates experienced over the last several years throughout the province is also evident in Fort Nelson. The Rate 1 and 2.1 projections for 2010 show a slight decline from the 2009 use rate and carries over to 2011. However, Rate 2.2 is showing a stable use per customer for 2009 to 2011.

A summary of historic and forecast use per customer rates for residential and commercial customers is set out below in Table 3-3 and has been used in the preparation of the 2011 forecast.

Table 3-3: Use per Customer Rates Declining since 2009

(in GJ/annum)

	2007	2008	2009	2010	2011
	Normal	Normal	Normal	Projection	Forecast
Rate 1	142	140	138	137	136
Rate 2.1	472	449	464	462	459
Rate 2.2	3,084	3,137	3,371	3,371	3,371

3.6 Energy Forecast

3.6.1 RESIDENTIAL/COMMERCIAL

The residential and commercial energy forecast is calculated by multiplying the use per customer rate by the applicable customer count. Compared with the projection for 2010, the total residential energy consumption for 2011 is expected to remain relatively stable, from 265 terajoules ("TJs") in 2010 to 263 TJs in 2011. Commercial consumption is also forecast to remain relatively stable from 286 TJs in 2010 to 285 TJs in 2011. The forecast for each year is provided in Table 3-4 below. Overall, residential and commercial energy consumption has been holding relatively stable since 2007, with decreases in use rates being offset by customer additions.

3.6.2 INDUSTRIAL

Canfor remains the only industrial customer served under Rate Schedule 25 in the TG Fort Nelson region. Recent developments in the U.S. housing markets have caused difficulties within the forestry industry. The closure in 2008 of Canfor's two facilities in Fort Nelson resulted in these two plants maintaining only heat load consumption. Although there aren't any operating mills in Fort Nelson their heating load consumption can fluctuate from year to year.

As Table 3-4 below demonstrates, industrial volumes have been declining for the past several years with the forecast for 2011 following that trend. Slowdown in the U.S. housing market, subsequent drop in demand for forest products and the strengthening of the Canadian currency has affected the lumber industry, which in turn has resulted in the non-operational mills in Fort Nelson. This is the primary reason for the decline in industrial volumes first experienced in late 2008.

Table 3-4: Declining Energy Demand

(in TJ/annum)

	2007	2008	2009	2010	2011
	Normal	Normal	Normal	Projection	Forecast
Rate 1	272	269	266	265	263
Rate 2.1	193	186	191	192	191
Rate 2.2	93	88	94	94	94
Rate 25	264	211	69	52	50
Total	**822**	**754**	**621**	**603**	**598**

3.6.3 REVENUE FORECAST

Revenue forecasts for each customer class are developed from the total energy forecasts and the applicable rates currently in effect. The decrease in revenue for 2011 from 2010 is therefore mainly attributable to the decline in commodity rates, partly offset by higher volumes due to growth in customers.

Table 3-5 below summarizes historical and forecast revenues for 2007 to 2011 by rate class. Years 2007 through 2009 represent actual normalized values. Projection year 2010 and 2011 forecast represent revenues at existing approved rates. Please refer to Section 9, Schedule 10.1 for more information.

Table 3-5: Lower Commodity Rates Driving Lower Revenue in 2011

(amounts in $ thousands)

	2007	2008	2009	2010	2011
	Normal	Normal	Normal	Projection	Forecast
Rate 1	2,298	2,539	2,391	2,152	2,137
Rate 2.1	1,634	1,781	1,779	1,650	1,620
Rate 2.2	747	863	839	773	762
Rate 25	235	231	141	111	108
Total	**4,914**	**5,414**	**5,150**	**4,687**	**4,626**

3.6.4 MARGIN FORECAST

Table 3-6 below summarizes historical and forecast margins for 2007 to 2011 by rate class. Margin is calculated by taking the revenue less the approved cost of gas. The increase in margin is in line with the growth in customers. Please refer to Section 9, Schedule 10.1 for additional information.

Table 3-6: TG Fort Nelson Customer Growth Results in Increasing Margin in 2011

(amounts in $ thousands)

	2007 Normal	2008 Normal	2009 Normal	2010 Projection	2011 Forecast
Rate 1	428	455	581	589	613
Rate 2.1	330	353	478	498	517
Rate 2.2	130	161	193	208	216
Rate 25	239	211	134	105	102
Total	**1,127**	**1,180**	**1,386**	**1,399**	**1,448**

3.7 Other Revenue

There are three components of Other Revenue, as shown in Section 9, Schedule 11:

- Late Payment Charges
- Revenue from Service Work (primarily connection charges and transfer fees); and
- Other (primarily non-sufficient funds cheque administration fees).

The 2011 forecast for these three items is based on an analysis of historical results, to establish the “typical” portion of total revenue that each of the above Other Revenue items represents. Once established it is assumed to remain stable over the forecast period.

3.8 Summary

TG Fort Nelson developed the forecast demand for natural gas with reference to the factors influencing customer additions and average use per customer. It is through considering factors influencing natural gas consumption, applying a methodology consistent with prior years, and by using the latest and best information available that TG Fort Nelson believes it has developed a reasonable demand forecast that is the most appropriate to be used in this RRA.

4 COST OF GAS

The forecast cost of gas sold is determined by multiplying forecast sales volumes by the approved gas cost recovery charge for each rate schedule. The gas cost recovery charge embedded within rates is based on the forecast gas costs for the next 12-month period, including the current balance within the Gas Cost Reconciliation Account ("GCRA"). As the actual commodity costs invariably differ from the forecast costs, consistent with past practice, any differences between the costs incurred to purchase gas and the gas cost recoveries collected through rates will continue to be collected in the GCRA. TG Fort Nelson is not requesting approval of forecast gas costs with this Application, however forecast gas costs, including unaccounted for gas ("UAF") estimates, are required in the determination of the GCRA forecasts.

UAF refers to gas that is not specifically accounted for in gas energy balance of receipts, deliveries, and operations use; UAF includes measurement variances and cannot be projected with precision. Consistent with past practice, the UAF percentages are calculated based on the historical five-year rolling average UAF percentage for the Fort Nelson service area. The cost of UAF related to the Sales rate classes is included in the cost of gas and recovered via the gas cost recovery charge; whereas the cost of UAF related to the Transportation Service Rate Schedule 25 is included in the determination of the delivery rates.

The TG Fort Nelson gas cost recovery charge is the same for all sales rate classes. The current gas cost recovery charge is $5.784 per GJ, approved by Commission Order No. G-100-10, dated June 10, 2010 and effective July 1, 2010. The GCRA balance at the end of 2010, net of tax, is projected to be a deficit of approximately $15 thousand (Section 9, Schedule 6.1, Line 6), with no remaining balance at the end of 2011. It is important to note that the cost of gas is a flow through and this Application deals only with TG Fort Nelson delivery rates.

Consistent with established Commission practice, Terasen Gas will continue to review and report on the gas costs and the gas cost recovery rates for TG Fort Nelson on a quarterly basis and, as necessary, will make application for any rate changes to recover the cost of gas. (The document entitled, "British Columbia Utilities Commission – Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Account Balance", issued as Appendix I to Commission Letter No. L-5-01, dated February 5, 2001, outlines the quarterly reporting process.)

Terasen Gas files the Third Quarter 2010 Gas Cost Report for TG Fort Nelson in early September 2010, but any resulting commodity cost changes would not affect the requests and proposals included in this Application.

5 OPERATING AND MAINTENANCE EXPENSES

5.1 Introduction

TG Fort Nelson has forecasted its O&M expenses for the year 2011 as part of determining its revenue requirements for that year. The O&M expenses included in this Application are required to continue to serve customers in a safe and efficient manner. TG Fort Nelson is experiencing relatively steady levels of O&M, with increases at or below the level of inflation.

5.2 Determination of O&M

For financial reporting purposes, the O&M costs for TG Fort Nelson are included in overall operating and maintenance expenses of Terasen Gas.

To determine the TG Fort Nelson-related total O&M costs, both actual and forecast, the following process is used:

1. Determine the TG Fort Nelson direct O&M costs. These costs consist of labour, vehicle usage, materials and services used in direct system operations, and customer billing related costs, determined on a per customer basis.

2. Allocate O&M costs from those Terasen Gas business units that provide functional support to TG Fort Nelson. These shared services costs would include charges related to Marketing, Information Technology, Gas Supply and Transmission, Finance and Regulatory, Facilities and Logistics, Legal and Government Affairs, Human Resources and the office of the President. The allocation basis used up to and including 2007 was TG Fort Nelson's sales volumes as a percentage of Terasen Gas' sales volumes. The resulting allocation factor of 0.4% was used to determine the TG Fort Nelson portion of the Shared Services.

   Effective 2008, by Commission Order No. G-27-08, in respect of the TG Fort Nelson 2008 Revenue Requirements Application, the Commission approved:

   > "*Shared Services received by TG Fort Nelson from TGI for 2008 are to be allocated to the Company on the basis of customers…*"

   Therefore, the Shared Services allocation was based on the 2008 projection of total customers served by Terasen Gas of 829,970 and the total customers served by TG Fort Nelson of 2,341 (refer to the 2008 Revenue Requirements Application, Response to Commission Information Request No. 2, Question 22.2). The calculation resulted in an allocation factor of 0.3% which was used for rates from 2008 through 2010. The same 0.3% allocation factor has been used for 2011 proposed rates, calculated in a consistent manner, based on the 2011 forecast average number of customers for Terasen Gas and TG Fort Nelson of 846,075 and 2,377 (Section 9, Schedule 9, Line 1), respectively.

3. The overhead capitalization rate is then applied to the sum of the direct and allocated O&M costs. The rate was changed from the 16% approved for 2009 to the 14% that was approved for Terasen Gas for 2010 and 2011 to arrive at the net O&M costs. This approach is consistent with past practice.
4. For 2010 and 2011, TG Fort Nelson has included in its forecast a reduction of $1 thousand and $3 thousand respectively (Section 9, Schedule 12, Line 15), representing anticipated HST savings. This amount was calculated as 0.3% of the estimated Terasen Gas HST savings.

Table 5-1 below provides a combined resource view of the direct and allocated O&M costs for 2009 actual, along with the 2010 year end projection and 2011 forecast. The O&M forecast for 2011 was determined in accordance with the methodology described above.

Table 5-1: O&M Resources Required for TG Fort Nelson Expenses

***(amounts in $ thousands)*[2]**

	2009 Actual	2009 Decision	2010 Projected	2011 Forecast
RESOURCE VIEW				
M&E Costs	$ 128	$ 145	$ 136	$ 141
COPE Costs	55	53	63	68
IBEW Costs	262	247	255	258
Total Labour Costs	**445**	**444**	**455**	**467**
Vehicle Costs	65	59	54	61
Employee Expenses	13	33	37	17
Materials	14	23	29	14
Computer Costs	24	24	31	34
Fees & Administration Costs	57	62	60	60
Contractor Costs	168	166	171	177
Facilities	39	29	32	42
Recoveries & Revenue	(41)	(49)	(62)	(56)
HST Savings	-	-	(1)	(3)
Total Non-Labour Costs	**339**	**346**	**351**	**345**
Total Gross O&M Expenses	**784**	**790**	**806**	**812**
Less Capitalized Overhead	(126)	(126)	(113)	(114)
Total Net O&M Expenses	**$ 658**	**$ 664**	**$ 693**	**$ 698**

Major changes in Gross O&M line items are discussed below:

Total Labour costs

Staffing at TG Fort Nelson includes one management and exempt ("M&E") and two IBEW employees. The M&E employee is responsible for managing all the large projects and managing IBEW staff. Forecasted wage increases in this area are at 3% for management, and per the union contract for IBEW charges. COPE labour charges are allocated from TGI in accordance with the methodology described above,.

Vehicle Costs

Due to decreasing regular capital activities, the portion of vehicle cost allocated to O&M is rising, resulting in an increase in 2011 over 2010.

[2] HST savings in 2010 are included for comparative purposes only and have no impact on 2010 Service Rates.

Employee Expenses

Recently TG Fort Nelson experienced redeployment of staff from nearby towns due to a high employee turnover. In turn, this led to higher employee expenses such as: meals, travel, and living out allowances. As staffing in Fort Nelson is expected to normalize, the employee expenses in 2011 are expected to decrease.

Lower materials O&M in 2011 is a result of the current forecast assuming a higher portion of tools costing in excess of $1,000, which leads to them being capitalized and not included in the O&M.

Contractor Costs

Some of the planned O&M station work, due to its complexity, is expected to be performed by third party contractors, giving rise to higher contractor costs in 2011.

Facilities

Previously, TG Fort Nelson was able to utilize lower cost contractors to do some of the yard and building maintenance work. Recently, it has become increasingly difficult to extend such contracts. In addition, there has been a reduction in the capital related work performed by the IBEW staff. To reduce the idle time, the IBEW staff are rescheduled to perform a larger portion of O&M related work. Overall, this results in the facilities cost being higher in 2011 vs. 2010.

The above pressures and opportunities, combined with customer growth, result in an increase in Gross O&M but the Gross O&M per customer remaining flat in 2011. When adjusted for inflation, the 2011 O&M per customer shows a reduction of $7 per customer over 2010 ($334 vs. $341). Table 5-2 below shows the calculations.

Table 5-2: Gross O&M per Customers

	2010	2011
Total Gross O&M Expense ($'000's)	806	812
Average Number of Customers	2,365	2,377
Inflation Rate	1.70%	2.11%
Gross O&M per Customer	$ 341	$ 341
2011 O&M in 2010 Dollars	$ 341	$ 334

5.3 Summary

TG Fort Nelson believes that the forecast amounts of O&M for the years 2010 and 2011 as included in this Application take into consideration the planned and required activities and the most appropriate forecasting methodologies for those years. They are required to continue to operate the TG Fort Nelson natural gas distribution system and to meet the needs of customers.

6 TAXES

6.1 Introduction

In carrying out its mandate as an energy service provider, TG Fort Nelson incurs taxes that are imposed by different governmental bodies. TG Fort Nelson manages these expenditures through the tax audit process and various tax planning strategies, as well as ongoing compliance activities. The tax expenses included in this RRA reflect the current substantively enacted tax legislation and have been properly calculated and applied in calculating the Company's cost of service.

In this section TG Fort Nelson discusses property taxes, income taxes, and other taxes to which the Company is subject, as well as how those taxes impact the cost of service in 2011.

6.2 Property Taxes

TG Fort Nelson pays property taxes on its land and improvements as defined under the Assessment Act. We have considered the key factors influencing property tax determination and prepared the 2011 property tax forecasts using established practices. We believe that our property tax forecasts accurately and reasonably reflect our future property tax liabilities. The following sections describe property tax concepts, our forecasting methodology, and projected property tax forecasts, and our management of property tax issues.

6.2.1 PROPERTY TAX CONCEPTS

The methodology we used to forecast the TG Fort Nelson 2011 property tax liability is consistent with established past practice. Simply put, property tax is a function of corporate revenues earned on gas consumed within municipal boundaries, property assessment values and property tax rates set by the various taxation authorities.

General taxes collected based on corporate revenue are levied directly by the local government for the provision of service within the municipality. In BC, utility companies are required to pay 1 (one) per cent of revenues from gas consumed in place of the general portion of taxes for all improvements, excluding buildings, which are used solely within a municipality or group of adjoining municipalities for local transmission or distribution. The revenue value used to calculate property tax is based on corporate revenues from 2 years ago. That is, the component of property tax associated with revenue calculation for the 2011 tax year is based on 2009 actual revenues. TG Fort Nelson taxes based on corporate revenues for the 2011 tax year increased by 4.5% based on the actual reported change in billed revenues between 2008 and 2009. This portion of taxes is expected to remain relatively flat (+/- 0.5%) until the 2015 taxation year.

Property assessments reflect the “market value” of each property at the legislated reference date. Valuations are performed by BC Assessment and are determined by provisions set out in the Assessment Act. The property assessment value determines how the municipal tax policy will be distributed to individual property owners and the proportionate share of the taxes for a property in relation to other properties within the property class.

The property class determines the tax rate that will be applied to the property based on the “use” of the property as prescribed by legislation. There are currently 9 classes of properties defined in the legislation, with Utility or Major Industry typically paying the highest tax rates.

Multiple tax rates apply to an individual tax notice and these may be influenced by one or more of the following four factors:

5. Municipal Tax Policy - this is determined by Council for general municipal taxes and is usually defined as a predetermined percentage of the total tax levy that Council wants to collect from a property class;

6. Provincial Tax Policy - applies to all rural properties and certain tax collectors (i.e. schools, some regional districts, hospital districts) and is based on fixed tax rate ratios;

7. The balancing of the Municipal budget - municipalities are required by legislation to produce balanced budgets and property tax is the mechanism by which balanced budgets are created; and

8. Individual property tax collection authorities and their budgets.

In total, property tax is a function of corporate revenue, property assessment and property class tax rate.

6.2.2 PROPERTY TAX FORECAST - 2011

The incorporation of Northern Rockies Regional Municipality on February 6th 2009 resulted in a merger of the Town of Fort Nelson and the Northern Rockies Regional District effective for the 2010 taxation year. Overall this should have a limited impact on property taxation given the bulk of the assessment was located in the Town of Fort Nelson. The Property Tax deferral account will collect all variances from actual payments less approved 2011 forecast expense.

For 2011, assessed values are estimated using 2010 actual assessments as the base. The assessment improvements, including pipeline, are anticipated to represent general market increases between 2% and 4%, while land is expected to increase at 15%. Increases in land for 2011 reflect estimated changes in market values between July 1, 2009 and June 30, 2010. Increases in improvements reflect anticipated changes to construction materials (i.e. steel) and labour costs used in the BC Assessment costing models for the valuation of utility assets. Mill rates are expected to increase resulting from increased pressures on municipal property taxation budgets and slowing assessment growth.

In 2010 significant events included:

- Incorporation of Northern Rockies Regional Municipality on February 6th 2009 resulted in a merger of the Town of Fort Nelson and the Northern Rockies Regional District; and
- Overall tax rate increased with merger; and
- Land values increased 20% to 30%.

In 2011 significant events taken into account include:

- Property tax based on revenues is expected to increase based on changes in actual reported billed revenues between 2009 and 2008;
- Increases in land market values are expected to continue until the 2011 tax year, after which land values are expected to level off;
- Assessments are expected to change for the 2011 tax year as compared to 2010 follows:

Table 6-1: TG Fort Nelson Increased Assessment Values by Asset Type

	Land % Change	Improvements % Change
Distribution Lines	15%	2%
Transmission Lines	15%	4%
Stations	5%	2%
Office	5%	3%

Table 6-2: TG Fort Nelson Property Tax Rates Increase from 2010 to 2011:

	% Change
First Nation	3%
General Municipal	2%
School	0%
Other	3%

Overall, property taxes are expected to increase in 2011 as compared to 2010 by 5%. Increases in billed revenues accounts for 32% of the total increase of change, while changes in property assessments and tax rates accounts for the remaining 68% of the increase.

6.3 Income Tax

TG Fort Nelson is subject to corporate income taxes imposed by the Federal and BC governments, and as such appropriately includes these costs in calculating the Company's revenue requirements. Income tax expense is determined based on taxable earnings calculated on the basis of revenues and expenses in accordance with the applicable provisions of the *Income Tax Act*, multiplied by the combined provincial and federal income tax rates. For regulatory purposes, income tax expense is calculated following the taxes payable method of accounting for income taxes, consistent with Commission approved past practice, at the corporate tax rate of 26.5% for 2011.

6.4 Other Taxes

6.4.1 CARBON TAX

The Carbon tax was implemented by the Province effective July 1, 2008, and is applicable to the consumption of fossil fuels consumed in the Province. The carbon tax represents a cost to the Company on its own consumption of fuel to operate motor vehicles and space heating. The carbon tax rate applicable to natural gas from July 1, 2010 to June 30, 2011 is 99.32 cents per GJ, and will rise to 124.15 cents per GJ July 1, 2011.

6.4.2 B.C. SOCIAL SERVICES TAX ("SST") AND ICE LEVY

The Province levies various sales and other taxes, commonly referred to as "PST" or provincial sales tax, on various goods and services. For TG Fort Nelson until June 30 2010, these taxes included the SST, a tax of 7% on purchases of tangible property and certain services that the Company used in its operations, and the ICE levy of 0.4% on purchases of energy including electricity and natural gas. Both the SST and ICE levy have been repealed June 30, 2010. The SST has been replaced by the BC component of the HST, described in 6.4.4 below.

6.4.3 GOODS AND SERVICES TAX ("GST")

The GST is a federal commodity tax exigible on goods and services at a rate of 5%. On July 1, 2010 in BC, the GST was replaced by the HST as described in 6.4.4 below.

6.4.4 HARMONIZED SALES TAX ("HST")

BC HST has been implemented in BC effective July 1, 2010, replacing the GST (see 6.4.3 above) and SST (see 6.4.2 above). The BC HST is a federally administered commodity tax exigible on goods and services at a rate of 12%, representing a federal component of 5% and a BC provincial component of 7%. Businesses are entitled to claim Input Tax Credits ("ITCs") on HST paid. However, large businesses will have their ITCs restricted during the first 8 years of HST implementation. ITCs for the provincial portion of HST (7%) will be restricted for most telecommunication expenses, passenger vehicles, heat and electricity, and meals and entertainment expenses.

TG Fort Nelson has included an estimate of the savings related to HST in its 2010 and 2011 forecasts – see Section 5.2 for more details of the calculation.

6.5 Summary

TG Fort Nelson will continue to incur income taxes, property taxes and other taxes that are imposed by different government bodies. TG Fort Nelson manages these expenditures through the tax audit process and various tax planning strategies, as well as ongoing compliance activities. The tax expenses included in this RRA reflect the current substantively enacted tax legislation and have been properly calculated and applied in calculating the Company's Cost of Service.

7 RATE BASE

7.1 Introduction

The 2011 rate base amount of $6.6 million as determined in Section 9, Schedule 2.0, Line 30 of this RRA, represents the average investment by the Company in utility assets necessary to provide safe and reliable service to our customers.

The determination of rate base is a significant step in the calculation of the revenue requirement; it forms the basis for the earned return component of the cost of service. The rate base is comprised of:

- Mid-year net plant in-service (gross plant in service, less contributions in aid of construction, less accumulated depreciation relating to both), adjusted for the timing of completion of major capital projects;
- Work-in-progress not attracting allowance for funds used during construction;
- Mid-year balance of unamortized deferred accounts (regulatory assets and liabilities); and
- 13 month average of cash working capital and other working capital.

In forecasting the composition and amount of rate base, TG Fort Nelson has incorporated these underlying principles:

- We must continue to provide the products and services that meet the expectations of our growing customer base;
- We must meet requirements to make improvements related to system integrity and reliability;
- We must invest in systems required to support customer growth; and
- We must ensure that the deferred charges we employ are adding value to customers and the shareholder.

The following subsections discuss in detail the various components of rate base. The calculation of rate base is shown under Section 9, Schedule 2.0.

7.2 Rate Base Overview

Table 7-1 below sets out the Company's rate base, for purposes of determining cost of service.

Table 7-1: Rate Base in 2011 is growing

(amounts in $ thousands)

	2009 Actual	2010 Projection	2011 Forecast
Net Plant in Service, Mid-Year	5,194	5,465	6,987
Adjustment to 13 - Month Average	(84)		(666)
Work In Progress, Not Attracting AFUDC	143	38	38
Construction Advances	-		
Unamortized Deferred Charges	79	100	154
Cash Working Capital	(290)	(287)	54
Other Working Capital	13	3	3
Utility Rate Base	$ 5,055	$ 5,320	$ 6,571

Each of the main components of rate base (plant balances, deferral accounts, and working capital) is discussed separately below.

7.3 Net Plant In-Service ("NPIS")

The mid-year NPIS balance of approximately $7.0 million in 2011 as per Table 7-1 above and Section 9, Schedule 2.0, Line 21 reflects the necessary additions to ensure that TG Fort Nelson is able to meet the evolving needs of our customers. As noted above, the mid-year NPIS is the sum of the averages of the gross plant in-service, contributions in aid of construction ("CIAC") and accumulated depreciation related to these two items.

7.3.1 GROSS PLANT IN-SERVICE ("GPIS")

The ending GPIS balance of $11.6 million in 2011, Section 9, Schedule 3.2, Line 41 is made up of the opening balance of GPIS plus plant additions, less retirements. Plant additions are comprised of capital expenditures adjusted for opening and closing work in progress ("WIP"), plus allowance for funds used during construction and overheads capitalized, where applicable.

Table 7-2 below summarizes TG Fort Nelson's plant additions for each of 2009 Decision and Actual, 2010 Projection, and 2011 Forecast.

Table 7-2: Summary of Gross Plant Additions

(amounts in $ thousands)

	2009 Decision	2009 Actual	2010 Projection	2011 Forecast
Customer Additions	12	(2)	13	12
TRANSMISSION PLANT				
Mains	$ -	$ -	$ -	$ 2,475
Measuring & Regulating Equipment	-	174	-	-
Total Transmission Plant	-	174	-	2,475
DISTRIBUTION PLANT:				
Structures & Improvements	-	2	-	-
Services	35	39	56	36
House Regulators & Meter Installation	4	5	3	3
Mains	59	35	62	61
Measuring & Regulating Equipment	50	23	58	85
Meters	3	-	3	3
Total Distribution Plant	151	104	182	189
GENERAL PLANT:				
Frame Structures & Improvements	20	33	404	-
Small Tools & Equipment	8	-	8	8
Total General Plant	28	33	412	8
Total Capital Additions	$ 179	$ 312	$ 594	$ 2,672

Plant additions are required to provide safe, reliable and cost effective natural gas service to new and existing customers. TG Fort Nelson proposes the 2011 plant additions as outlined in Table 7-2 above and compares these with the 2009 Decision. These expenditures exclude Contribution In Aid of Construction ("CIAC"), and overheads capitalized, but include AFUDC.

A description of the major changes in plant additions over the years 2009 to 2011 follows.

Transmission Mains

Natural Gas service to the Fort Nelson area is provided by a single 114mm transmission pressure pipeline that crosses the Muskwa River on the southeast side of the town. This pipeline has become exposed and is now at risk of damage from river action. Expenditures in the Transmission Mains category are required to replace the pipeline crossing. Based on work completed to date, TG Fort Nelson considers that a pipeline replacement using HDD methodology will likely be the most cost-effective strategy. The status of the HDD evaluation and other potential alternatives are discussed in Section 7.3.2 below. Total project costs for this option are currently estimated at $2.45 million (excluding AFUDC). Of this total, $2.35 million will be added to rate base in 2011, with the remaining $100 thousand being added in 2012.

Distribution Services

Capital expenditures in 2010 are higher than that of 2009 due to an increase in the services category. This increase is primarily due to expenditures required for the replacement of existing Services to enable proper filtration and regular equipment testing.

Measuring and Regulating Equipment (Distribution and Transmission)

Capital expenditures in 2009 for Measuring and Regulating Equipment are primarily attributable to a project to upgrade the piping at the Fort Nelson Odorizer Station, approved as part of TG Fort Nelson's 2009 Revenue Requirements and Rates Application. This project required the installation of additional equipment to address concerns that existed at the inlet from Spectra. The maximum operating pressure of the Fort Nelson pipeline system was less than that of the Spectra system which required installation of pressure control valves and overpressure protection device in order to reduce pressure from the Spectra system. The project was initiated in 2008 and originally forecast to be completed over a two year period for a total project cost of $100 thousand. Actual project costs totalled $174 thousand over 2008 and 2009. These increases are mainly attributable to material costs associated with the addition of a standby pressure control run to ensure greater reliability of gas supply and the addition of a skid to raise piping off the ground to provide better footing for employees maintaining the equipment.

Capital expenditures in 2010 and 2011 for Measuring and Regulating Equipment are attributable to the Muskwa Gate Station Project. This project involves replacing obsolete valves, stations and regulators and filters at the Muskwa Gate Station in order to maintain the safety, reliability and integrity of the station.

Structures and Improvements

The large expenditure in 2010 on Structures and Improvements is to replace the Fort Nelson Muster Shop and Storage Building to support operational requirements. The two existing buildings are currently at the end of their useful lives (40 and 48 years old respectively) and would require significant repairs in order to ensure a safe and healthy workplace, which would not be cost-effective given the age and condition of these buildings.

7.3.2 MUSKWA RIVER CROSSING PROJECT

7.3.2.1 Overview of Existing Facilities

Natural Gas service to Fort Nelson is provided by a 19 km long transmission pipeline connecting the Spectra Transmission System to the Gate Station serving Fort Nelson. The pipeline crosses the Muskwa River approximately 3 kilometres southeast of Fort Nelson at Km Post 17+300. This crossing is approximately 75 metres upstream of the Alaska Highway Bridge crossing of the Muskwa River.

The original crossing of the Muskwa River was completed in 1960 during the original pipeline construction by installing a 114mm diameter (NPS 4) pipe on the existing highway bridge. In 1973, the bridge was due to be replaced and the pipeline operators decided to install a replacement 168mm diameter (NPS 6) pipeline with an in-stream installation immediately upstream of the new bridge location. The installation was completed in 1974 by using an open-cut method. Figure 1-1 below shows a picture of the location of this crossing in relation to the bridge.

Figure 1-1: An Aerial View of the Muskwa River Showing the River Crossing

7.3.2.2 Project Justification

TG Fort Nelson, as part of its pipeline monitoring program, completed a survey of this pipeline crossing on September 28, 2008. The survey profile indicated approximately 12 metres of exposed pipe on the north side of the channel. The pipeline will be inspected again in 2010 to determine the current extent of exposure. The results of this subsequent survey may influence the level of concern and schedule for any pipeline repair or replacement alternative.

7.3.2.3 Potential Pipeline Failure Scenarios

For the pipeline that is exposed, a number of scenarios could result in an immediate impact on pipe integrity or potentially create a future integrity concern. Threats include:

- Line strike by a large boulder or cobble during a high flow event, resulting in a large dent with a gouge or potentially a line fracture;
- Line strike by a third party operating on the river in either a commercial or recreational fashion, potentially resulting in a dent, gouge or line fracture; or
- Excessive pipe deflection caused by further erosion, resulting in an unsupported exposed length of pipe potentially causing buckling or a failure of the pipe; and
- An unsupported length of pipe can also be subjected to oscillations caused by the river current which, in turn, could result in fatigue and subsequent failure of the pipe.

7.3.2.4 Consequences of Failure

The pipeline crossing the Muskwa River is the only natural gas source for the community of Fort Nelson. At the end of 2009, Fort Nelson natural gas customers include 1,925 residential, 412 small commercial, 28 large commercial and 2 industrial. As Fort Nelson is a northern community, the provision of natural gas for space heating is especially critical. Loss of the pipeline at this crossing would completely cut the delivery of natural gas to the community, leaving customers to rely upon other forms of heat including wood or electricity, depending on how each home is equipped. As the river crossing is close to the community, the line pack could not be relied upon for any meaningful time.

7.3.2.5 Justification Summary

Based on the information currently available, and considering the length of exposed pipe in the river and the consequences of failure, TG Fort Nelson considers the project risk to be high and concludes that a “do nothing” option is unacceptable. Consequently, Terasen has initiated a number of studies to determine the most effective method of remediating or replacing the crossing.

7.3.2.6 Alternatives Under Consideration

TGI retained Chinook Engineering Limited ("Chinook") to identify and evaluate repair/replace alternatives. Chinook initially identified and evaluated the following four alternatives:

1. Replacement crossing – Horizontal Direction Drill
2. Replacement crossing – Open Cut
3. In-Stream Remediation – Live Line Lowering
4. Replacement Crossing – Intermediate Pressure Bridge Crossing.

A copy of the Chinook report summarizing these alternatives is attached as Appendix A.

TGI subsequently requested Chinook evaluate in-stream alternatives in greater detail. In a follow up report, Chinook identified and evaluated the following two additional alternatives:

1. In-Stream Remediation – Cabled Concrete Mats
2. In-Stream Remediation – Rip Rap Placement

These two additional alternatives are summarized in a second Chinook report attached as Appendix B.

The following sections summarize the six alternatives and provide cost estimates, risks and uncertainties, and a summary of the preliminary status of the work to date.

7.3.2.7 Alternatives Evaluated by Chinook

As discussed, Chinook identified and evaluated six alternatives altogether. For each alternative a Class 4 cost estimate with tolerances of -30% to +50% was developed in accordance with AACE Recommended Practice No. 18R-97. Also, a preliminary schedule was developed for each alternative taking into account preliminary evaluations of regulatory and permitting constraints. The alternatives also took into account environmental considerations but these were based on Chinook's assessment, not the results of an independent environmental evaluation.

7.3.2.7.1 <u>Replacement Crossing - Horizontal Directional Drill Crossing</u>

HDD is frequently selected as a crossing methodology for any high fish and fish habitat watercourses where suitable subsurface geology exists.

An HDD of the Muskwa River would be approximately 460 metres in length based on the preliminary 'peak to peak' design layout shown in Appendix A. A second 'low to high' drill alignment may also be feasible. This second alignment would be considerably shorter at 270 metres in length but would result in greater disturbance as the entry pad would be located on the gravel bar within the watercourse.

As sub-surface conditions are unknown, TGI has retained BGC Engineering to investigate the subsurface geological conditions to assist in determining if an HDD option is feasible. Once this information becomes available, an HDD consultant will be retained to determine the feasibility and risks associated with an HDD installation at this location.

7.3.2.7.2 Replacement Crossing – Open Cut

As the name implies, an open cut crossing involves excavating a trench across the river, lowering a new pipeline crossing into the trench, filling in the trench, and restoring the river bed. To the extent possible, the trench is made by excavators located on the shore but some in-stream works may be required.

This methodology has a significant impact on both the river itself and the riparian zones adjacent to the river. From a construction standpoint, an open cut crossing of the Muskwa River is difficult but feasible. However, regulatory permits to allow in–stream works may be very difficult or impossible to obtain.

7.3.2.7.3 In Stream Remediation – Live Line Lowering

This method would be similar to the open cut crossing method described previously. To complete a live pipeline lowering, the operating pipeline will have to be supported by supports or machines (cranes, side-booms). Excavators on barges or a drag line would be employed to open an eroding trench across the watercourse. Due to the high volume flow of the river, it will be extremely difficult to maintain trench integrity/stability in the silty-sandy base of the river and the resulting excavation will most likely be up to 30m to 40m wide. Once the trench is deep enough, the existing line is lowered into the trench, covered, and the river bed restored.

An additional complication is that the existing line should, to the greatest extent possible, be inspected to ensure long term integrity before it is lowered into the trench and that the pipe integrity is maintained throughout the lowering and covering process.

This method will likely have an even greater environmental impact than a new, open cut crossing due to the difficulty in controlling the excavation below the live line. Significant permitting issues are anticipated due to the extent of the probable in-stream works and the necessary regulatory permits may be very difficult or impossible to obtain.

7.3.2.7.4 Replacement Crossing - Intermediate Pressure Bridge Crossing

In this alternative, the crossing of the Muskwa River would be accomplished by attaching a new pipeline to the existing Alaska Highway bridge that is located just downstream of the existing crossing. It has been Terasen's experience that bridge authorities are reluctant to allow new, transmission pressure pipelines to be attached to the bridge structure but may allow a lower pressure pipeline to be installed in this manner.

In the current system, transmission pressure pipe extends all the way to the Fort Nelson Gate Station. In this alternative, a new Transmission Pressure to Intermediate Pressure ("TP" to "IP") station would be installed upstream of the bridge and an IP pipeline attached to the bridge structure. The existing pressure regulating pressure station at Fort Nelson would be modified to accept a lower inlet pressure.

Because the bridge is part of the Alaska Highway system, it is a federally regulated structure. Preliminary discussions with the Federal Department of Public Works indicated that they are generally opposed to attaching a natural gas pipeline of any pressure to the highway bridge.

An independent assessment will have to be completed to determine the suitability of the bridge to support the considered pipeline.

It will also be necessary to determine the impact of lowering the operating pressure between the bridge and Fort Nelson on future system reinforcement plans.

7.3.2.7.5 In Stream Remediation - Cabled Concrete Mats

This in-stream alternative is the installation of a number of cable connected concrete mats which are placed over the entire pipeline crossing in the river to effectively blanket the pipeline and protect the pipeline cover from further erosion due to river action. The mats and cables are pre-fabricated and transported to the site for placement by lifting equipment large enough to safely place the mats over the pipeline. Placement in the river must be completed during low flow conditions.

This methodology has a significant impact on both the river itself and the riparian zones From a construction standpoint, the logistics of this installation are difficult but feasible. Again, regulatory permits to allow this or other in–stream works may be very difficult or impossible to obtain.

7.3.2.7.6 In Stream Remediation - Rip Rap Placement

This in-stream alternative is similar to the previous method, with the difference being that the placed material is loose. Suitably sized aggregate is placed over the entire pipeline crossing in the river to effectively blanket the pipeline and protect the pipeline cover from further erosion due to river action. Placement is completed by excavators or draglines large enough to safely place the material over the pipeline.

As with the other considered in-stream works, this alternative has a significant impact on both the river and riparian zones. Again, regulatory permits to allow this or other in–stream works may be very difficult or impossible to obtain.

7.3.2.8 Cost Estimates

Cost estimates for the four alternatives evaluated by Chinook are summarized in Table 7-3. All costs are in $ million (2009).

Table 7-3: Cost Estimate Summary for Alternatives Evaluated by Chinook

(amounts in $ millions)

Alternative	Lower Bound (-30%)	Mean	Upper Bound (+50%)
HDD Crossing (Peak to Peak)	$1.14	$1.64	$2.45
HDD Crossing (Low to High)	$1.05	$1.49	$2.24
Open Cut Crossing	$1.29	$1.84	$2.76
Live Line Lowering	$1.37	$1.96	$2.93
IP Bridge Crossing	$1.55	$2.21	$3.32
Concrete Mats	$1.30	$1.85	$2.78
Rip Rap Placement	$1.75	$2.50	$3.74

7.3.2.9 Current Uncertainties for the Chinook Alternatives

As described below, each alternative has a level of uncertainty that exists at this time:

- HDD – geotechnical evaluation is required to confirm feasibility and acceptable level of risk;
- New Open Cut Crossing – further assessment required of the extent of environmental impact and likelihood of obtaining the necessary permits;
- Lowering of the Existing Crossing – further assessment required of the extent of environmental impact and the likelihood of obtaining the necessary permits;

- IP Bridge Crossing – further assessment of the feasibility of installing the pipeline on the existing bridge, likelihood of obtaining permission to install a pipeline on the bridge, and long term impact on future system reinforcement plans;
- Concrete Mats – further assessment required of the extent of environmental impact and likelihood of obtaining necessary permits and confirmation that river hydrology supports this form of pipeline protection; and
- Rip Rap Placement - further assessment required of the extent of environmental impact and likelihood of obtaining necessary permits and confirmation that river hydrology supports this form of pipeline protection.

7.3.2.10 Other Alternatives Under Consideration

An aerial pipeline crossing of the Muskwa can theoretically avoid all of the problems identified for the other options. Although TG Fort Nelson considers it unlikely that this method of crossing would be cost competitive, all of the alternatives evaluated by Chinook have potential "showstoppers", so TG Fort Nelson considers it prudent to do a preliminary evaluation of the aerial crossing alternative. Accordingly, TGI has contracted the firm of Buckland & Taylor to provide a conceptual design and preliminary cost estimate of an aerial crossing of the Muskwa River. Should the preliminary estimate indicate that it is cost competitive, TG Fort Nelson will consider an aerial crossing when making a final decision.

7.3.2.11 Other Work Required

As a result of the uncertainties associated with the various alternatives, a final selection cannot be made until further work has been completed. In addition to the geotechnical evaluation previously mentioned, the following work is also required, depending on the alternative selected:

- Environmental and archaeological reviews of the crossing site are underway (performed by EDI Environmental Dynamics Inc.);
- A topographic survey of the crossing site is underway (performed by Can-Am Geomatics Inc.);
- Aerial Crossing Conceptual Design & Cost Estimate is underway (performed by Buckland & Taylor);
- First Nations discussion has been initiated;
- Environmental impact and permit assessments of open-cut and in-stream remediation alternatives may be required;
- Assessment of the feasibility of installing a pipeline on the existing Muskwa River bridge may be required;

- Although preliminary discussion has been undertaken, further discussion with approving agency to obtain permission to install a pipeline on the bridge may be initiated; and
- Assessment of lowering pipeline pressure on future system reinforcement plans may be required.

7.3.2.12 Conclusion and Recommendation

Based on the information available at this time, TG Fort Nelson considers the "peak to peak" HDD pipeline installation to be the preferred alternative, for both financial and non-financial reasons. A preliminary cost estimate and spending profile for the project follows.

Table 7-4: Preliminary Cost Estimate and Spending Profile

Year	Amount	Description
2010	$300,000	Project development and alternative evaluation costs
2011	$2,050,000	HDD installation and allowance for cost escalation[3]
2012	$100,000	Site restoration costs
Total	**$2,450,000**	

TG Fort Nelson recognizes the degree of uncertainty as to the final alternative that will be chosen and cost that will be incurred. Although material to Fort Nelson, the Muskwa project is not the primary contributor to the revenue deficiency in 2011 (contributing approximately $50 thousand), since it is not scheduled to come into service until October of 2011. The HDD alternative included in this Application is both the lowest cost and most desirable of the alternatives available to deal with this integrity related project based on the information available at this time. Either the unsuitability of an HDD crossing, or a change in conditions related to the HDD crossing could result in an estimate above the $2.45 million, or another alternative being more cost-effective. TG Fort Nelson commits that, following completion of the site surveys, geotechnical evaluation, and other related alternative evaluation studies, TG Fort Nelson will review all the alternatives and select the most appropriate solution. When a final alternative is selected and a final Class 3 cost estimate is completed, TG Fort Nelson will file an Evidentiary Update at that time. If the final estimate is materially different than the amount included in the Application, then depending on the timing of completion of that estimate, TG Fort Nelson will

[3] Given the uncertainty of the information currently available and the broad range of the Class 4 estimate, Terasen does not consider it appropriate to rely upon the mean cost for the HDD option and considers the mean plus 25% as a more appropriate estimate to be used at this time. The result is half way between the mean and the upper bound for a Class 4 estimate for the project.

either request updated 2011 rates or propose regulatory treatment of the difference at that time. When TG Fort Nelson applies for 2012 rates, it will include its best estimate of the costs of the Muskwa River Crossing Project at that time, based on actuals to date and an estimate of any remaining expenditures.

TG Fort Nelson is requesting that the Commission accept the Muskwa River Crossing Project ("the Project") under Section 44.2(b) of the Utilities Commission Act. With respect to the items the Commission must consider under section 44.2(5) of the Utilities Commission Act, TG Fort Nelson believes that:

1. The Project does nothing to hamper British Columbia's energy objectives, as it serves to maintain infrastructure to meet future needs;
2. The Project is consistent with the Terasen Utilities' 2010 Long-term Resource Plan, and was also included in Appendix D-4 of that Plan;
3. Sections 6 and 19 of the Clean Energy Act do not apply to the Project;
4. Consideration of demand side measures are not relevant to the Project; and
5. The Project is in the best interests of Fort Nelson customers who receive service from Terasen Gas.

7.3.3 CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)

Gross CIAC is composed of opening contributions plus additions and less retirements throughout the year. The year end CIAC amounts of $1.3 million in 2011 (Section 9 Schedule 5.1 Line 20.) are unchanged from the 2010 ending balance, since TG Fort Nelson CIAC are usually of small dollar value and difficult to predict, and therefore no change to CIAC are forecast.

7.3.4 ACCUMULATED DEPRECIATION

The depreciation rates used for 2010 and 2011 are the same rates used in the TGI RRA and approved in Commission Order No. G-141-09. The impact of the change in depreciation rates for 2010 has been recorded in the IFRS Transitional Deferral Account as approved by Commission Order No. G-147-09 (see Table 7-6 below for a summary of the changes). Depreciation for 2011 has been calculated on the mid-year plant balances, to align with Commission Order No. G-141-09 for TGI.

The rate base of TG Fort Nelson includes both the accumulated depreciation of plant in service, and accumulated amortization of CIAC. Both are increased through depreciation expense, and decreased through retirements.

7.4 13-Month Adjustment

Rate base calculations assume that plant additions are included into rate base at mid-year. Therefore, a rate base reduction of $666 thousand (Section 9, Schedule 2.0, Line 23) is necessary to reflect an October 1, 2011 in-service date for the Muskwa River Crossing project.

7.5 Work in Progress

Consistent with past practice, Work in Progress included in Rate Base represents construction work in progress for projects that are shorter than three months in duration and less than $50 thousand. Projects over this threshold attract AFUDC, and are not included in rate base until they are available for use, at which time AFUDC is no longer charged to the capital project.

7.6 Deferral Accounts

TG Fort Nelson has maintained those deferral accounts that continue to provide benefits as appropriate to customers and our Company in 2011. The mid-year balances of the deferral accounts that have been included in rate base are included in Table 7-4 below.

Table 7-4: Deferral Balances included in Rate Base benefit Customers

(amounts in $ thousands)

	2009 Actual	2010 Projection	2011 Forecast
GCRA	(77)	(6)	8
RSAM	129	25	32
RSAM Interest	6	5	4
Property Tax Deferral	5	(4)	-
Deferred Interest	11	(1)	(3)
ROE & Capital Structure Deferral	5	33	28
IFRS Transitional Deferral	-	38	75
Revenue Requirment Application	-	11	11
Total Deferred Charges in Rate Base	79	100	154

7.6.1 GAS COST RECONCILIATION ACCOUNT (GCRA)

The GCRA accumulates the actual costs incurred by TG Fort Nelson to purchase gas, and the revenue collected through the commodity portion of TG Fort Nelson's rates. As commodity recovery rates are based on forecast gas costs, and actual costs invariably differ from the forecast costs, the GCRA captures those variances for future recovery from or refund to customers. Consistent with Commission guidelines, commodity rates are subject to quarterly review, and when they are reset, the new rate is typically designed to recover or refund, over the next 12 months, any existing GCRA account balance, along with any increase or decrease in commodity costs forecast to occur over the next 12-month period.

7.6.2 REVENUE STABILIZATION ADJUSTMENT MECHANISM (RSAM) / RSAM INTEREST

The RSAM is a mechanism that stabilizes the Company's delivery margin revenue, enabling the Company to record delivery margin revenue based on the forecast use per customer for each customer segment that was used in establishing rates for Rates 1, 2.1 and 2.2, and based on forecast volumes for Rate 25. Further discussion of this mechanism is included in Section 2.3.1, along with the calculation of the RSAM Rider 5 for 2011.

Any variances from forecasting the RSAM account are subject to deferred interest treatment at the Company's short-term borrowing rate. The booking of interest on variances reduces the likelihood of large carrying cost benefits or losses accruing to either the Company or to customers. The deferred interest amounts are recovered from or returned to customers using the same methodology as for the associated RSAM account.

7.6.3 PROPERTY TAX DEFERRED

TG Fort Nelson has limited ability to influence property taxes, which are imposed by municipalities and other levels of government, and are influenced by assessed property values, mill rates, and shortfalls in other areas within a municipal boundary. A significant portion of property taxes is tied to the amount of revenues collected within a municipality ("1 per cent in lieu" tax), and fluctuates with commodity-related variations in revenues. Further information on property tax and related risks is found in Section 6.2. TG Fort Nelson will continue to defer the variance between actual and forecast property taxes, as most recently approved by Commission Order No. G-147-09, and amortize it in rates the following year.

7.6.4 DEFERRED INTEREST

Interest rates have historically been difficult to predict. To avoid potential gains or losses on forecasting of interest rates, TG Fort Nelson proposes to continue the Deferred Interest variance account. This account captures the Fort Nelson portion of the Terasen Gas Inc. deferred interest account, and amortizes it into rates in the following year. This deferral was most recently approved by Commission Order No. G-147-09.

7.6.5 2011 RRA DEFERRAL ACCOUNT

TG Fort Nelson will incur costs in 2010 to prepare this Revenue Requirement application, consisting of legal fees, consulting costs, intervener and participant funding costs, Commission costs, required public notifications, and miscellaneous facilities, stationery and supplies costs. Consistent with past practice, TG Fort Nelson proposes to defer these costs in 2010 for recovery in 2011.

7.6.6 ROE & CAPITAL STRUCTURE DEFERRAL

Approved by Commission Order No, G-147-09, the ROE & Capital Structure Deferral Account captures the impact of the change in ROE and Capital Structure based on the actual rate base for TG Fort Nelson for each of 2009 and 2010. With this Application, TG Fort Nelson is requesting amortization of the 2010 projected ending balance of $56 thousand in 2011 (Section 9, Schedule 6.1, Line 7). The calculation is shown in Table 7-5 below.

Table 7-5: Approved Change in ROE and Equity Thickness to be Recovered from Customers

	2009	2010	Total
Final Approved ROE	8.99%	9.50%	
Original Approved ROE	8.47%	8.47%	
Variance	0.52%	1.03%	
Final Approved Equity %	35.01%	40.00%	
Original Approved Equity %	35.01%	35.01%	
Variance	0.00%	4.99%	
Rate Base (2009 actual, 2010 forecast)	$ 5,055,000	$ 5,320,000	
Variance due to change in Approved ROE	$ 9,114	$ 21,918	$ 31,032
Variance due to change in Approved Equity %	-	25,219	25,219
Deferral account addition	$ 9,114	$ 47,137	$ 56,251

7.6.7 IFRS TRANSITIONAL DEFERRAL ACCOUNT

Approved by Commission Order No. G-147-09, the IFRS Transitional Deferral Account captures:

1. The impact of the change in depreciation rates as determined in the TGI revenue Requirement Application for 2010; and

2. The impact of the change in overheads capitalized rate as determined in the TGI Revenue Requirement Application for 2010; and

3. Any unanticipated IFRS impacts determined by the application of accounting policies approved for use by TGI.

In 2010, TG Fort Nelson has recorded $59 thousand as the impact of the change in depreciation rates (calculation is shown in Table 7-6 below) and a further $16 thousand as the impact of the change in overheads capitalized ($807 thousand multiplied by 2% (16% less 14%)). TG Fort Nelson is not proposing a recovery period for this account in this application; a recovery period will be proposed for the IFRS Transitional Deferral Account in the next Terasen Gas Inc.

Revenue Requirement Application, as TG Fort Nelson proposes keeping the recovery period consistent with that of Terasen Gas Inc.

Table 7-6: Impact of Depreciation on Rate Base

(amounts in $ thousands)

Class	Description	Current Rate	Recommended Depreciation Rate	2010 Opening Balance	Total Depreciation Increase + / Decrease
NATURAL GAS & PETROLEUM PIPELINE SYSTEMS					
46300	TP Meas/Reg Structures	3.00%	4.27%	$ 3	$ 0
46400	TP Other Structures	3.00%	2.88%	1	(0)
46500	TP Transmission Pipeline	2.00%	1.63%	731	(3)
46700	TP Meas/Reg Equipment	3.00%	7.19%	379	16
46710	TP Telemetry Equipment	10.00%	1.33%	4	(0)
47200	DS Structures	3.00%	3.60%	245	1
47300	DS Services	2.00%	2.25%	2,246	6
47400	DS Meters/Regulators Installations	3.57%	5.21%	644	11
47500	DS Mains	2.00%	1.89%	2,011	(2)
47710	DS Meas/Reg Additions	3.00%	5.72%	1,113	30
47720	DS Telemetry	10.00%	0.25%	14	(1)
47810	DS Meters	3.57%	5.31%	32	1
				7,420	58
PLANT, BUILDING AND EQUIPMENT					
48210	GP (Frame) Structures	3.00%	3.67%	256	2
48310	GP Computer Hardware	20.00%	20.00%	182	0
40201	Application Software - 8 yr life	12.50%	12.50%	135	0
48330	GP Office Equipment	5.00%	6.67%	15	0
48340	GP Furniture	5.00%	5.00%	25	0
48400	GP Vehicles	15.00%	6.16%	11	(1)
48510	GP Heavy Work Equipment	5.00%	6.64%	3	0
48600	GP Small Tools/Equipment	5.00%	5.00%	92	0
48810	GP Telephone Equipment	5.00%	6.67%	25	0
48820	GP Radio Equipment	10.00%	6.67%	2	(0)
				747	1
	Total Annual Depreciation			$ 8,167	$ 59
	Annual Composite Rate based on Current Rate			3.0%	
	Annual Composite Rate based on Recommended Rate			3.7%	

TG Fort Nelson believes that the deferral accounts requested above serve to add value to customers and our shareholder and appropriately address uncontrollable matters for the 2011 period.

7.7 Cash Working Capital

Cash Working Capital is defined as the average amount of capital provided by investors in the Company to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. The periods are usually expressed in terms of lead or lag days, and are supported by a Lead Lag Study. Cash working capital of $54 thousand (Section 9, Schedule 7.0, Line 11 in 2011 has been deducted from rate base.

As part of the Terasen Gas Inc. 2010-2011 Revenue Requirements Application, a Lead Lag Study was completed, which resulted in updated estimated of working capital requirements. The results of the Lead Lag Study were approved as part of the Negotiated Settlement for Terasen Gas Inc.

TG Fort Nelson is proposing to adopt the results of this updated Lead Lag Study in 2011. A comparison of the current and updated days is provided in Table 7-7 below.

Table 7-7: Lead Lag Days Reflect the Updated Study

	Current	Updated
Lead Days:		
Residential & Commercial Revenues	34.6	38.3
Small Industrial Revenues	47.2	45.2
Late Payment Charge	26.7	38.3
All Other Revenue	34.9	38.3
Revenue from Service Work	41.9	38.3
Lag Days:		
Operating & Maintenance Expense	19.3	25.5
Cost of Gas	40.7	40.2
Property Taxes	4.0	2.0
Goods & Service Tax	41.7	n/a
Social Services Tax	43.8	n/a
Carbon Tax	43.6	29.1
Harmonized Sales Tax	n/a	7.2
Income Tax	15.2	15.2

When applied to the revenues and operating expenses for 2011, this change in net days results in an increase of approximately $124 thousand in cash required for operating expenses as compared to the previously approved days.

The final step in the calculation of cash working capital is to adjust the cash working capital for the reserve for bad debts and the withholdings from employees. The reserve for bad debts has been forecast based on customer additions and customer deposit requirements, while employee withholdings are calculated based on historical levels. Consistent with the approved treatment in Terasen Gas Inc. and Commission Order No. G-112-04, customer security deposits are no longer included as a component of the working capital calculation. They are treated as part of unfunded debt, and the difference between the interest rate applicable to security deposits and the unfunded debt rate is included in the deferred interest variance account.

The working capital requirements that have been included in this RRA appropriately reflect the most recent Lead Lag Study results and represent the amounts required to compensate TG Fort Nelson for the timing differences between when expenditures are required to provide service and when collections are received for that service. TG Fort Nelson therefore requests approval of the adoption of the cash working capital lead lag days as set out in Section 9, Schedule 7.0.

7.8 Other Working Capital

Other working capital consists of inventories of pipe and fittings. The 2011 forecast costs for these items have been calculated based on historical levels for inventories. Please refer to Section 9, Schedule 8.0.

7.9 Rate Base Summary

The rate base amounts that have been forecast for 2011 incorporate required expenditures to meet the expectations of our growing customer base, make improvements related to system integrity and reliability, and ensure that the deferred charges we employ are adding value to customers and the shareholder.

8 FINANCING AND CAPITAL STRUCTURE

8.1 Introduction

TG Fort Nelson and the other three Terasen Gas service areas (Lower Mainland, Inland and Columbia) share the same debt and equity percentages for their capital structure: 60% debt and 40% equity as recently approved by Commission Order No. G-158-09. Please refer to Section 9, Schedule 15.5 for Long-Term Debt, Unfunded Debt and Common Equity values for the years 2009 through 2011. In this section, TG Fort Nelson provides additional information on the debt and equity components of the Company's Capital Structure.

8.2 Debt

Debt consists of long-term debt and unfunded debt. The Company's long-term debt represents an allocation from Terasen Gas Inc. The 2011 amount and interest rate were approved as part of the Terasen Gas Inc. 2010-2011 Revenue Requirements Negotiated Settlement. Unfunded debt represents the difference between the long-term debt and 60% of rate base.

8.2.1 LONG-TERM DEBT

The 2011 forecast average embedded cost of long term debt for TG Fort Nelson is 6.945% and represents approximately 47% of the capital structure funding rate base (Section 9, Schedule 15.5, Line 27).

8.2.2 UNFUNDED DEBT

The forecast cost of unfunded debt for TG Fort Nelson for 2011 is 4.50%, consistent with the rate approved in the Terasen Gas Inc. 2010-2011 Revenue Requirements Negotiated Settlement. Unfunded debt represents approximately 13% of the capital structure funding rate base (Section 9, Schedule 15.5, Line 26).

8.3 Common Equity

The 2011 common equity component of the capital structure is 40% and the Return on Equity ("ROE") is 9.5% (Section 9, Schedule 15.5, Line 28), both approved by Commission Order No. G-158-09.

8.4 Summary

The Company continues to prudently manage its capital structure and address its financing requirements, to meet the needs of its various stakeholders.

9 FINANCIAL SCHEDULES

TG FORT NELSON

2011 REVENUE REQUIREMENT AND RATES APPLICATION

Revenue Requirment Summary ($000s)

September 8, 2010

Section 9
Schedule 1.0

Line No.	Description	2009 Decision	2011 Forecast @ Existing Rates	Difference	Reference
	(1)	(2)	(3)	(4)	(5)
1		**a**	**b**	**c = b - a**	
2	**Revenue**				
3	Residential/Commercial	$ 5,854	$ 4,519	$ (1,335)	Section 9, Schedule 10.1
4	Transportation Service	41	108	67	Section 9, Schedule 10.1
5	**Total Revenue:**	**5,895**	**4,626**	**(1,269)**	
6	Less:				
7	Cost of Gas	4,476	3,179	(1,297)	Section 9, Schedule 10.1
8	**Gross Margin:**	**1,419**	**1,448**	**29**	
9					
10	**Cost of Service (excl. COG)**				
11	O&M	664	698	35	Section 9, Schedule 12.0 & 12.1
12	Property Tax	158	165	7	Section 9, Schedule 13.0
13	Depreciation	185	284	99	Section 9, Schedule 14.0
14	Amortization	6	71	66	Section 9, Schedule 14.0
15	Income Tax	59	83	24	Section 9, Schedule 15.0
16	Interest Expense	232	251	19	Section 9, Schedule 15.4
17	Other Revenue	(45)	(60)	(15)	Section 9, Schedule 11.0
18	Return on Equity	160	250	90	Section 9, Schedule 15.5
19	**Total Cost of Service:**	**1,419**	**1,743**	**324**	
20					
21	**Surplus/(Deficiency):**	**$ 0**	**$ (295)**	**$ (295)**	X-Ref - Section 9, Schedule 10.1
22					
23					
24	Revenue Deficiency (Surplus) as a % of Gross Margin			**20.37%**	
25	Revenue Deficiency (Surplus) as a % of Total Revenue			**6.37%**	X-Ref - Section 9, Schedule 10.1

TG FORT NELSON

2011 REVENUE REQUIREMENT AND RATES APPLICATION

Utility Rate Base ($000s)

September 8, 2010

Line No.	Particulars	2009 Actual	2009 Decision	2010 Projected	2011 At Existing Rates	2011 Adjustment	2011 At Revised Rates	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Gross Plant in Service**							
2	GPIS Beginning of Year	$ 7,865	$ 7,965	$ 8,146	$ 8,809	$ -	$ 8,809	Section 9, Schedule 3.2
4	GPIS End of Year	8,146	8,300	8,809	11,565	-	11,565	Section 9, Schedule 3.2
5	GPIS Average Mid-Year Balance	8,005	8,132	8,477	10,187	-	10,187	
6								
7	CIAOC Beginning of Year	(1,179)	(1,159)	(1,271)	(1,271)	-	(1,271)	Section 9, Schedule 5.1
8	CIAOC End of Year	(1,271)	(1,159)	(1,271)	(1,271)	-	(1,271)	Section 9, Schedule 5.1
9	CIAOC Average Mid-Year Balance	(1,225)	(1,159)	(1,271)	(1,271)	-	(1,271)	
10								
11	**Accumulated Depreciation**							
12	GPIS Beginning of Year	(2,021)	(2,064)	(2,033)	(2,342)	-	(2,342)	Section 9, Schedule 4.2
14	GPIS End of Year	(2,033)	(2,271)	(2,342)	(2,626)	-	(2,626)	Section 9, Schedule 4.2
15	GPIS Average Mid-Year Balance	(2,027)	(2,167)	(2,238)	(2,484)	-	(2,484)	
16								
17	CIAOC Beginning of Year	429	554	452	541	-	541	Section 9, Schedule 5.1
18	CIAOC End of Year	453	576	541	570	-	570	Section 9, Schedule 5.1
19	CIAOC Average Mid-Year Balance	441	565	497	555	-	555	
20								
21	**Net Plant in Service, Mid-Year**	**$ 5,194**	**$ 5,371**	**$ 5,465**	**$ 6,987**	**$ -**	**$ 6,987**	
22								
23	Adjustment to 13 - Month Average	(84)	-	-	(666)	-	(666)	
24	Work In Progress, Not Attracting AFUDC	143	-	38	38	-	38	
26	Unamortized Deferred Charges	79	307	100	154	-	154	Section 9, Schedule 6.1
27	Cash Working Capital	(290)	(277)	(287)	49	6	54	Section 9, Schedule 7.0
28	Other Working Capital	13	3	3	3	-	3	Section 9, Schedule 8.0
29								
30	**Utility Rate Base**	**$ 5,055**	**$ 5,405**	**$ 5,320**	**$ 6,565**	**$ 6**	**$ 6,571**	X-Ref - Section 9, Schedule 9.0

TG FORT NELSON

2011 REVENUE REQUIREMENT AND RATES APPLICATION

Gas Plant in Service ($000s)

September 8, 2010

Line No.	Particulars	CCA Class	Account No.	Opening Balance	Adjustments	Additions	AFUDC	Overhead Capitalized	Retirements	Closing Balance	Mid-year GPIS for Depreciation	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	**2009 ACTUAL**											
2	**Transmission**											
3	Land / Land Rights	land/rights	460-00/461-00	$ 9	$ -	$ (1)		$ -	$ -	$ 9		
4	Measuring & Regulating Structures	49	463-00	3	-	-		-	(3)	-		
5	Other Structures & Improvements	7	464-00	1	-	-		-	-	1		
6	Mains	49	465-00	715	-	-		-	(8)	706		
7	Measuring & Regulating Equipment	49	467-00	379	-	174		79	(63)	569		
8	Telemetering	49	467-10	5	-	-		-	-	5		
9	Communication Equipment	49	468-00	-	-	-		-	-	-		
10	**Total Transmission**			**1,111**	**-**	**174**		**79**	**(74)**	**1,290**		
11												
12	**Distribution**											
13	Land / Land Rights	land/rights	470-00/471-00	24	-	-		-	-	24		
14	Structures & Improvements	1	472-00	245	-	2		1	-	247		
15	Services	1	473-00	2,183	1	39		18	(45)	2,195		
16	House Regulators & Meter Installation	1	474-00	638	-	5		2	(18)	628		
17	Mains	1	475-00	1,926	-	35		16	(2)	1,976		
18	Compressed Natural Gas	8	476-00	-	-	-		-	-	-		
19	Measuring & Regulating Equipment	1	477-10/477-30	977	-	23		10	(9)	1,001		
20	Telemetering	1	477-20	13	-	-		-	-	13		
21	Meters	1	478-10	28	-	-		-	(4)	24		
22	**Total Distribution**			**6,034**	**1**	**104**		**47**	**(78)**	**6,108**		
23												
24	**General Plant**											
25	Land	land	480-00	1	-	-		-	-	1		
26	Frame Structures & Improvements	1	482-00	236	-	33		-	-	269		
27	Office Furniture & Equipment	8	483-00									
28	Computers - Hardware	45	483-10	182	-	-		-	-	182		
29	Computers - Software (non-infrastructure)	12	402-01	135	-	-		-	(6)	130		
30	Computers - Software (infrastructure/custom)	12	483-20	-	-	-		-	-	-		
31	Office Equipment	8	483-30	41						41		
32	Furniture	8	483-40	-	-	-		-	-	-		
33	Transportation Equipment	10	484-00	11	-	-		-	-	11		
34	Heavy Work Equipment	38	485-10/485-20	3	-	-		-	-	3		
35	Small Tools & Equipment	8	486-00	84	-	-		-	(1)	84		
36	Communication Equipment											
37	Telephone	8	488-10	27	-	-		-	-	27		
38	Radios	8	488-20	-	-	-		-	-	-		
39	**Total General Plant**			**720**		**33**		**-**	**(6)**	**747**		
40												
41	**Total**			**$ 7,865**	**$ 2**	**$ 312**		**$ 126**	**$ (158)**	**$ 8,146**		

TG FORT NELSON
2011 REVENUE REQUIREMENT AND RATES APPLICATION
Gas Plant in Service ($000s)
September 8, 2010

Line No.	Particulars	CCA Class	Account No.	Opening Balance	Adjustments	Additions	AFUDC	Overhead Capitalized	Retirements	Closing Balance	Mid-year GPIS for Depreciation	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	**2010 PROJECTED**											
2	**Transmission**											
3	Land / Land Rights	land/rights	460-00/461-00	$ 9	$ -	$ -		$ -	$ -	$ 9		
4	Measuring & Regulating Structures	49	463-00	-	-	-		-	-	-		
5	Other Structures & Improvements	7	464-00	1	-	-		-	-	1		
6	Mains	49	465-00	706	-	-		-	-	706		
7	Measuring & Regulating Equipment	49	467-00	569	-	-		-	-	569		
8	Telemetering	49	467-10	5	-	-		-	-	5		
9	Communication Equipment	49	468-00	-	-	-		-	-	-		
10	**Total Transmission**			**1,290**	**-**	**-**		**-**	**-**	**1,290**		
11												
12	**Distribution**											
13	Land / Land Rights	land/rights	470-00/471-00	24	-	-		-	-	24		
14	Structures & Improvements	1	472-00	247	-	-		-	-	247		
15	Services	1	473-00	2,195	-	56		35	-	2,287		
16	House Regulators & Meter Installation	1	474-00	628	-	3		2	-	633		
17	Mains	1	475-00	1,976	-	62		39	-	2,076		
18	Compressed Natural Gas	8	476-00	-	-	-		-	-	-		
19	Measuring & Regulating Equipment	1	477-10/477-30	1,001	-	58		37	-	1,096		
20	Telemetering	1	477-20	13	-	-		-	-	13		
21	Meters	1	478-10	24	-	3		-	-	27		
22	**Total Distribution**			**6,108**	**-**	**182**		**113**	**-**	**6,403**		
23												
24	**General Plant**											
25	Land	land	480-00	1	-	-		-	-	1		
26	Frame Structures & Improvements	1	482-00	269	-	404		-	(44)	629		
27	Office Furniture & Equipment	8	483-00	-	-	-		-	-	-		
28	Computers - Hardware	45	483-10	182	-	-		-	-	182		
29	Computers - Software (non-infrastructure)	12	402-01	130	-	-		-	-	130		
30	Computers - Software (infrastructure/custom)	12	483-20	-	-	-		-	-	-		
31	Office Equipment	8	483-30	41	-	-		-	-	41		
32	Furniture	8	483-40	-	-	-		-	-	-		
33	Transportation Equipment	10	484-00	11	-	-		-	-	11		
34	Heavy Work Equipment	38	485-10/485-20	3	-	-		-	-	3		
35	Small Tools & Equipment	8	486-00	84	-	8		-	-	92		
36	Communication Equipment											
37	Telephone	8	488-10	27	-	-		-	-	27		
38	Radios	8	488-20	-	-	-		-	-	-		
39	**Total General Plant**			**747**		**412**		**-**	**(44)**	**1,115**		
40												
41	**Total**			**$ 8,146**	**$ -**	**$ 594**		**$ 113**	**$ (44)**	**$ 8,809**		

TG FORT NELSON Section 9

2011 REVENUE REQUIREMENT AND RATES APPLICATION Schedule 3.2

Gas Plant in Service ($000s)

September 8, 2010

Line No.	Particulars	CCA Class	Account No.	Opening Balance	Adjustments	Additions	AFUDC	Overhead Capitalized	Retirements	Closing Balance	Mid-year GPIS for Depreciation	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	**2011 FORECAST**											
2	**Transmission**											
3	Land / Land Rights	land/rights	460-00/461-00	$ 9	$ -	$ -		$ -	$ -	$ 9	$ 9	X-Ref - Section 9, Schedule 4.2
4	Measuring & Regulating Structures	49	463-00	-	-	-		-	-	-	-	X-Ref - Section 9, Schedule 4.2
5	Other Structures & Improvements	7	464-00	1	-	-		-	-	1	1	X-Ref - Section 9, Schedule 4.2
6	Mains	49	465-00	706	-	2,350	125	-	(29)	3,153	1,930	X-Ref - Section 9, Schedule 4.2
7	Measuring & Regulating Equipment	49	467-00	569	-	-		-	-	569	569	X-Ref - Section 9, Schedule 4.2
8	Telemetering	49	467-10	5	-	-		-	-	5	5	X-Ref - Section 9, Schedule 4.2
9	Communication Equipment	49	468-00	-	-	-		-	-	-	-	X-Ref - Section 9, Schedule 4.2
10	**Total Transmission**			**1,290**	**-**	**2,350**	**125**	**-**	**(29)**	**3,737**	**2,514**	
11												
12	**Distribution**											
13	Land / Land Rights	land/rights	470-00/471-00	24	-	-		-	-	24	24	X-Ref - Section 9, Schedule 4.2
14	Structures & Improvements	1	472-00	247	-	-		-	-	247	247	X-Ref - Section 9, Schedule 4.2
15	Services	1	473-00	2,287	-	36		22	-	2,346	2,316	X-Ref - Section 9, Schedule 4.2
16	House Regulators & Meter Installation	1	474-00	633	-	3		2	-	638	635	X-Ref - Section 9, Schedule 4.2
17	Mains	1	475-00	2,076	-	61		37	-	2,175	2,126	X-Ref - Section 9, Schedule 4.2
18	Compressed Natural Gas	8	476-00	-	-	-		-	-	-	-	X-Ref - Section 9, Schedule 4.2
19	Measuring & Regulating Equipment	1	477-10/477-30	1,096	-	85		52	-	1,233	1,164	X-Ref - Section 9, Schedule 4.2
20	Telemetering	1	477-20	13	-	-		-	-	13	13	X-Ref - Section 9, Schedule 4.2
21	Meters	1	478-10	27	-	3		-	-	30	29	X-Ref - Section 9, Schedule 4.2
22	**Total Distribution**			**6,403**	**-**	**189**	**-**	**114**	**-**	**6,706**	**6,554**	
23												
24	**General Plant**											
25	Land	land	480-00	1	-	-		-	-	1	1	X-Ref - Section 9, Schedule 4.2
26	Frame Structures & Improvements	1	482-00	629	-	-		-	-	629	629	X-Ref - Section 9, Schedule 4.2
27	Office Furniture & Equipment	8	483-00	-						-	-	X-Ref - Section 9, Schedule 4.2
28	Computers - Hardware	45	483-10	182	-	-		-	-	182	182	X-Ref - Section 9, Schedule 4.2
29	Computers - Software (non-infrastructure)	12	402-01	130	-	-		-	-	130	130	X-Ref - Section 9, Schedule 4.2
30	Computers - Software (infrastructure/custom)	12	483-20	-	-	-		-	-	-	-	X-Ref - Section 9, Schedule 4.2
31	Office Equipment	8	483-30	41	-	-		-	-	41	41	X-Ref - Section 9, Schedule 4.2
32	Furniture	8	483-40	-	-	-		-	-	-	-	X-Ref - Section 9, Schedule 4.2
33	Transportation Equipment	10	484-00	11	-	-		-	-	11	11	X-Ref - Section 9, Schedule 4.2
34	Heavy Work Equipment	38	485-10/485-20	3	-	-		-	-	3	3	X-Ref - Section 9, Schedule 4.2
35	Small Tools & Equipment	8	486-00	92	-	8		-	-	100	96	X-Ref - Section 9, Schedule 4.2
36	Communication Equipment										-	X-Ref - Section 9, Schedule 4.2
37	Telephone	8	488-10	27	-	-		-	-	27	27	X-Ref - Section 9, Schedule 4.2
38	Radios	8	488-20	-	-	-		-	-	-	-	X-Ref - Section 9, Schedule 4.2
39	**Total General Plant**			**1,115**		**8**		**-**	**-**	**1,123**	**1,119**	
40												
41	**Total**			**$ 8,809**	**$ -**	**$ 2,547**	**$ 125**	**$ 114**	**$ (29)**	**$ 11,565**	**$ 10,187**	X-Ref - Section 9, Schedule 2.0

TG FORT NELSON

2011 REVENUE REQUIREMENT AND RATES APPLICATION

Accumulated Depreciation ($000s)

September 8, 2010

Line No.	Particulars	Account No.	Annual Depn Rate %	GPIS, Opening Balance	Acc Depn Opening Balance	Opening Adj	Depn Provision	Adjustments	Retirements	Disposal Costs	Proceeds on Disposal	Acc Depn Ending Balance	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	**2009 ACTUAL**												
2	**Transmission**												
3	Land / Land Rights	460-00/461-00	0.00%	$ 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
4	Measuring & Regulating Structures	463-00	3.00%	3	-	-	-	-	(3)	-	-	(3)	
5	Other Structures & Improvements	464-00	3.00%	1	(2)	-	-	-	-	-	-	(2)	
6	Mains	465-00	2.00%	715	24	-	12	-	(8)	-	-	27	
7	Measuring & Regulating Equipment	467-00	3.00%	379	52	-	11	-	(63)	-	-		
8	Telemetering	467-10	10.00%	5	(2)	-	1	-	-	-	-	(2)	
9	Communication Equipment	468-00	0.00%	-	-	-	-	-	-	-	-		
10	**Total Transmission**			**1,111**	**72**	**-**	**23**	**-**	**(74)**	**-**	**-**	**21**	
11													
12	**Distribution**												
13	Land / Land Rights	470-00/471-00	0.00%	24	-	-	-	-	-	-	-	-	
14	Structures & Improvements	472-00	3.00%	245	46	-	7	-	-	-	-	53	
15	Services	473-00	2.00%	2,183	719	-	40	-	(45)	-	-	714	
16	House Regulators & Meter Installation	474-00	3.57%	638	195	-	21	-	(18)	-	-	198	
17	Mains	475-00	2.00%	1,926	413	-	36	-	(2)	-	-	447	
18	Compressed Natural Gas	476-00	6.67%	-	(97)	-	-	-	-	-	-	(97)	
19	Measuring & Regulating Equipment	477-10/477-30	3.00%	977	223	-	27	-	(9)	-	-	241	
20	Telemetering	477-20	10.00%	13	11	-	1	-	-	-	-	12	
21	Meters	478-10	3.57%	28	5	-	1	-	(4)	-	-	2	
22	**Total Distribution**			**6,034**	**1,515**	**-**	**133**	**-**	**(78)**	**-**	**-**	**1,570**	
23													
24	**General Plant**												
25	Land	480-00	0.00%	1	0	-	-	-	-	-	-	0	
26	Frame Structures & Improvements	482-00	3.00%	236	172	-	7	-	-	-	-	178	
27	Office Furniture & Equipment	483-00	0.00%										
28	Computers - Hardware	483-10	20.00%	182	229	-	-	-	-	-	-	229	
29	Computers - Software	402-01	12.50%	135	12	-	1	-	(6)	-	-	7	
30	Office Equipment	483-30	5.00%	41	20	-	-	-	-			20	
31	Furniture	483-40	5.00%	-	-	-	-	-	-	-	-	-	
32	Transportation Equipment	484-00	15.00%	11	(26)	-	-	-	-	-	-	(26)	
33	Heavy Work Equipment	485-10/485-20	5.00%	3	(52)	-	-	-	-	-	-	(52)	
34	Small Tools & Equipment	486-00	5.00%	84	48	-	4	-	(1)	-	-	51	
35	Communication Equipment	488-00	5.00%	25	24	-	1	-	-			25	
36	Telephone	488-10	5.00%	-	-	-	-	-	-	-	-	-	
37	Radios	488-20	10.00%	2	8	-	-	-	-	-	-	8	
38	**Total General Plant**			**720**	**434**	**-**	**13**	**-**	**(6)**	**-**	**-**	**442**	
39													
40	**Total**			**$ 7,865**	**$ 2,021**	**$ -**	**171**	**$ -**	**$ (158)**	**$ -**	**$ -**	**$ 2,033**	

Accumulated Depreciation ($000s)

Line No.	Particulars	Account No.	Annual Depn Rate %	GPIS, Opening Balance	Acc Depn Opening Balance	Opening Adj	Depn Provision	Adjustments	Retirements	Disposal Costs	Proceeds on Disposal	Acc Depn Ending Balance	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	**2010 PROJECTED**												
2	**Transmission**												
3	Land / Land Rights	460-00/461-00	0.00%	$ 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
4	Measuring & Regulating Structures	463-00	4.27%	-	(3)	5	-	-	-	-	-	2	
5	Other Structures & Improvements	464-00	2.88%	1	(2)	-	0	-	-	-	-	(2)	
6	Mains	465-00	1.63%	706	27	4	12	-	-	-	-	43	
7	Measuring & Regulating Equipment	467-00	7.19%	569	-	33	41	-	-	-	-	74	
8	Telemetering	467-10	1.33%	5	(2)	-	0	-	-	-	-	(2)	
9	Communication Equipment	468-00	0.00%	-	-	-	-	-	-	-	-	-	
10	**Total Transmission**			**1,290**	**21**	**42**	**53**	**-**	**-**	**-**	**-**	**115**	
11													
12	**Distribution**												
13	Land / Land Rights	470-00/471-00	0.00%	24	-	-	-	-	-	-	-	-	
14	Structures & Improvements	472-00	3.60%	247	53	-	9	-	-	-	-	62	
15	Services	473-00	2.25%	2,195	714	39	49	-	-	-	-	802	
16	House Regulators & Meter Installation	474-00	5.21%	628	198	11	33	-	-	-	-	241	
17	Mains	475-00	1.89%	1,976	447	2	37	-	-	-	-	487	
18	Compressed Natural Gas	476-00	0.00%	-	(97)	-	-	-	-	-	-	(97)	
19	Measuring & Regulating Equipment	477-10/477-30	5.72%	1,001	241	7	57	-	-	-	-	305	
20	Telemetering	477-20	0.25%	13	12	-	0	-	-	-	-	12	
21	Meters	478-00	5.31%	24	2	1	1	-	-	-	-	5	
22	**Total Distribution**			**6,108**	**1,570**	**60**	**187**	**-**	**-**	**-**	**-**	**1,817**	
23													
24	**General Plant**												
25	Land	480-00	0.00%	1	0	-	-	-	-	-	-	0	
26	Frame Structures & Improvements	482-00	3.67%	269	178	-	10	-	(44)	(20)	-	124	
27	Office Furniture & Equipment	483-00	0.00%	-	-	-	-	-		-	-	-	
28	Computers - Hardware	483-10	20.00%	182	229	-	-	-	-	-	-	229	
29	Computers - Software	402-01	12.50%	130	7	-	16	-	-	-	-	23	
30	Office Equipment	483-30	6.67%	41	20	-	3	-	-	-	-	23	
31	Furniture	483-40	5.00%	-	-	(1)	-	-	-	-	-	(1)	
32	Transportation Equipment	484-00	6.16%	11	(26)	-	-	-	-	-	-	(26)	
33	Heavy Work Equipment	485-10/485-20	6.64%	3	(52)	-	0	-	-	-	-	(52)	
34	Small Tools & Equipment	486-00	5.00%	84	51	-	4	-	-	-	-	56	
35	Communication Equipment	488-00	6.67%		25	-	-	-		-	-	25	
36	Telephone	488-10	6.67%	27	-	-	2	-	-	-	-	2	
37	Radios	488-20	6.67%	-	8	-	-	-	-	-	-	8	
38	**Total General Plant**			**747**	**440**	**(1)**	**35**	**-**	**(44)**	**(20)**	**-**	**410**	
39													
40	**Total**			**$ 8,146**	**$ 2,033**	**$ 101**	**$ 274**	**$ -**	**$ (44)**	**$ (20)**	**$ -**	**$ 2,342**	

Accumulated Depreciation ($000s)

Line No.	Particulars	Account No.	Annual Depn Rate %	GPIS, Average Balance	Acc Depn Opening Balance	Opening Adj	Depn Provision	Adjustments	Retirements	Disposal Costs	Proceeds on Disposal	Acc Depn Ending Balance	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	**2011 FORECAST**												
2	**Transmission**												
3	Land / Land Rights	460-00/461-00	0.00%	$ 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Section 9, Schedule 3.2
4	Measuring & Regulating Structures	463-00	4.27%	-	2	-	-	-	-	-	-	2	Section 9, Schedule 3.2
5	Other Structures & Improvements	464-00	2.88%	1	(2)	-	0	-	-	-	-	(2)	Section 9, Schedule 3.2
6	Mains	465-00	1.63%	1,264	43	-	21	-	(29)	-	-	34	Section 9, Schedule 3.2
7	Measuring & Regulating Equipment	467-00	7.19%	569	74	-	41	-	-	-	-	115	Section 9, Schedule 3.2
8	Telemetering	467-10	1.33%	5	(2)	-	0	-	-	-	-	(2)	Section 9, Schedule 3.2
9	Communication Equipment	468-00	0.00%	-	-	-	-	-	-	-	-	-	Section 9, Schedule 3.2
10	**Total Transmission**			**1,848**	**115**	**-**	**62**	**-**	**(29)**	**-**	**-**	**148**	X-Ref - Section 9, Schedule 14.0
11													
12	**Distribution**												
13	Land / Land Rights	470-00/471-00	0.00%	24	-	-	-	-	-	-	-	-	Section 9, Schedule 3.2
14	Structures & Improvements	472-00	3.60%	247	62	-	9	-	-	-	-	71	Section 9, Schedule 3.2
15	Services	473-00	2.25%	2,316	802	-	52	-	-	-	-	854	Section 9, Schedule 3.2
16	House Regulators & Meter Installation	474-00	5.21%	635	241	-	33	-	-	-	-	274	Section 9, Schedule 3.2
17	Mains	475-00	1.89%	2,126	487	-	40	-	-	-	-	527	Section 9, Schedule 3.2
18	Compressed Natural Gas	476-00	0.00%	-	(97)	-	-	-	-	-	-	(97)	Section 9, Schedule 3.2
19	Measuring & Regulating Equipment	477-10/477-30	5.72%	1,164	305	-	67	-	-	-	-	372	Section 9, Schedule 3.2
20	Telemetering	477-20	0.25%	13	12	-	0	-	-	-	-	12	Section 9, Schedule 3.2
21	Meters	478-00	5.31%	29	5	-	2	-	-	-	-	6	Section 9, Schedule 3.2
22	**Total Distribution**			**6,554**	**1,817**	**-**	**202**	**-**	**-**	**-**	**-**	**2,019**	X-Ref - Section 9, Schedule 14.0
23													
24	**General Plant**												
25	Land	480-00	0.00%	1	0	-	-	-	-	-	-	0	Section 9, Schedule 3.2
26	Frame Structures & Improvements	482-00	3.67%	629	124	-	23	-	-	-	-	147	Section 9, Schedule 3.2
27	Office Furniture & Equipment	483-00	0.00%	-	-	-	-	-	-	-	-	-	Section 9, Schedule 3.2
28	Computers - Hardware	483-10	20.00%	182	229	-	-	-	-	-	-	229	Section 9, Schedule 3.2
29	Computers - Software	402-01	12.50%	130	23	-	16	-	-	-	-	40	Section 9, Schedule 3.2
30	Office Equipment	483-30	6.67%	41	23	-	3	-	-	-	-	25	Section 9, Schedule 3.2
31	Furniture	483-40	5.00%	-	(1)	-	-	-	-	-	-	(1)	Section 9, Schedule 3.2
32	Transportation Equipment	484-00	6.16%	11	(26)	-	-	-	-	-	-	(26)	Section 9, Schedule 3.2
33	Heavy Work Equipment	485-10/485-20	6.64%	3	(52)	-	0	-	-	-	-	(52)	Section 9, Schedule 3.2
34	Small Tools & Equipment	486-00	5.00%	96	56	-	5	-	-	-	-	60	Section 9, Schedule 3.2
35	Communication Equipment	488-00	6.67%	-	25	-	-	-	-	-	-	25	Section 9, Schedule 3.2
36	Telephone	488-10	6.67%	27	2	-	2	-	-	-	-	4	Section 9, Schedule 3.2
37	Radios	488-20	6.67%	-	8	-	-	-	-	-	-	8	Section 9, Schedule 3.2
38	**Total General Plant**			**1,119**	**410**	**-**	**49**	**-**	**-**	**-**	**-**	**459**	X-Ref - Section 9, Schedule 14.0
39													
40	**Total**			**$ 9,521**	**$ 2,342**	**$ -**	**$ 313**	**$ -**	**$ (29)**	**$ -**	**$ -**	**$ 2,626**	X-Ref - Section 9, Schedule 2.0

Section 9
Schedule 5.0

Contributions in Aid of Construction Continuity Schedules ($000s)

September 8, 2010

Line No.	Particulars	Opening Balance	Additions	Retirements	Ending Balance	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**2009 Actual**					
2	Gross Contributions					
3	DSEP / GEAP	$ -	$ -	$ -	$ -	
4	Computer Software Tax Credit	-	-	-	-	
5	Other	1,179	92	-	1,271	
6	Total Gross Contributions	1,179	92	-	1,271	
7						
8	Accumulated Amortization					
9	Computer Software Tax Savings	-	-	-	-	
10	Other	(429)	(24)	-	(452)	
11	Total Accumulated Amortization	(429)	(24)	-	(452)	
12						
13	**Total 2009 Actual Net CIAOC**	**$ 750**	**$ 69**	**$ -**	**$ 819**	
14						
15	**2009 Decision**					
16	Gross Contributions					
17	DSEP / GEAP	$ 248	$ -	$ -	$ 248	
18	Computer Software Tax Credit	156	-	-	156	
19	Other	755	-	-	755	
20	Total Gross Contributions	1,159	-	-	1,159	
21						
22	Accumulated Amortization					
23	Computer Software Tax Savings	(156)	-	-	(156)	
24	Other	(398)	(22)	-	(420)	
25	Total Accumulated Amortization	(554)	(22)	-	(576)	
26						
27	**Total 2009 Decision Net CIAOC**	**$ 605**	**$ (22)**	**$ -**	**$ 583**	

Contributions in Aid of Construction Continuity Schedules ($000s)

Line No.	Particulars	Opening Balance	Additions	Retirements	Ending Balance	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**2010 Projected**					
2	Gross Contributions					
3	DSEP / GEAP	$ -	$ -	$ -	$ -	
4	Computer Software Tax Credit	-	-	-	-	
5	Other	1,271	-	-	1,271	
6	Total Gross Contributions	1,271	-	-	1,271	
7						
8	Accumulated Amortization					
9	Computer Software Tax Savings	-	-	-	-	
10	Other	(452)	(89)	-	(541)	
11	Total Accumulated Amortization	(452)	(89)	-	(541)	
12						
13	**Total 2010 Projected Net CIAOC**	**$ 819**	**$ (89)**	**$ -**	**$ 730**	
14						
15	**2011 Forecast**					
16	Gross Contributions					
17	DSEP / GEAP	$ -	$ -	$ -	$ -	
18	Computer Software Tax Credit	-	-	-	-	
19	Other	1,271	-	-	1,271	
20	Total Gross Contributions	1,271	-	-	1,271	X-Ref - Section 9, Schedule 2.0
21						
22	Accumulated Amortization					
23	Computer Software Tax Savings	-	-	-	-	
24	Other	(541)	(29)	-	(570)	
25	Total Accumulated Amortization	(541)	(29)	-	(570)	X-Ref - Section 9, Schedule 2.0, 14.0
26						
27	**Total 2011 Forecast Net CIAOC**	**$ 730**	**$ (29)**	**$ -**	**$ 701**	

TG FORT NELSON Section 9

2011 REVENUE REQUIREMENT AND RATES APPLICATION Schedule 6.0

Deferred Charges ($000s)

September 8, 2010

Line No.	Particulars	Opening Balance	Adjustments	Gross Additions	Less Taxes	Net Additions	Amortization Expense	Amortization Other / Int.	Closing Balance	Mid-Year Average	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**2009 ACTUAL**										
2	Deferred Interest	$ 17	$ -	$ (18)	$ 5	$ (13)	$ -	$ -	$ 4	11	
3	Property Tax Deferral	18	-	(17)	5	(12)	(15)	-	(9)	5	
4	RSAM	246	-	(165)	101	(65)	-	(170)	12	129	
5	RSAM Interest	6	-	(1)		(1)	-	-	5	6	
6	GCRA	(129)	-	147	(44)	103	-	-	(26)	(77)	
7	ROE & Capital Structure Deferral			9		9			9	5	
8	IFRS Transitional Deferral										
9											
10	**Total 2009 ACTUAL**	**$ 159**	**$ -**	**$ (45)**	**$ 67**	**$ 22**	**$ (15)**	**$ (170)**	**$ (4)**	**$ 79**	
11											
12	**2009 Decision**										
13	Deferred Interest	$ (9)		$ -	$ -	$ -	$ 9	$ -	$ -	$ (5)	
14	Property Tax Deferral	15		-	-	-	(15)	-	-	7	
15	RSAM	276		(134)	40	(94)	-		182	229	
16	RSAM Interest	6		(0)	0	(0)	-	2	4	5	
17	GCRA	142		(203)	61	(142)	-	-	(0)	71	
18	ROE & Capital Structure Deferral								-	-	
19	IFRS Transitional Deferral								-	-	
20											
21	**Total 2009 Decision**	**$ 429**	**$ -**	**$ (337)**	**$ 101**	**$ (236)**	**$ (6)**	**$ 2**	**$ 186**	**$ 307**	

Deferred Charges ($000s)

September 8, 2010

Line No.	Particulars	Opening Balance	Adjustments	Gross Additions	Less Taxes	Net Additions	Amortization Expense	Amortization Other / Int.	Closing Balance	Mid-Year Average	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**2010 Projected**										
2	Deferred Interest	$ 4	$ -	$ (2)	$ 1	$ (1)	$ (9)	$ -	$ (6)	$ (1)	
3	Property Tax Deferral	(9)	-	-	-	-	9	-	-	(4)	
4	RSAM	12	-	52	(15)	37	-	(11)	38	25	
5	RSAM Interest	5	-	0	(0)	0	-	(0)	5	5	
6	GCRA	(26)	-	58	(16)	41	-	-	15	(6)	
7	ROE & Capital Structure Deferral	9		47	-	47			56	33	
8	IFRS Transitional Deferral			75	-	75			75	38	
9	Revenue Requirment Application			30	(9)	21			21	11	
10											
11	**Total 2010 Projected**	**$ (4)**	**$ -**	**$ 260**	**$ (39)**	**$ 220**	**$ (1)**	**$ (12)**	**$ 204**	**$ 100**	
12											
13	**2011 Forecast**										
14	Deferred Interest	$ (6)	$ -	$ -	$ -	$ -	$ 6	$ -	$ -	$ (3)	
15	Property Tax Deferral	-	-	-	-	-	-	-	-	-	
16	RSAM	38	-		-	-	-	(13)	25	32	
17	RSAM Interest	5	-		-	-		(2)	3	4	
18	GCRA	15	-	(21)	5	(15)	-	-	-	8	
19	ROE & Capital Structure Deferral	56		-		-	(56)		-	28	
20	IFRS Transitional Deferral	75		-		-			75	75	
21	Revenue Requirment Application	21					(21)			11	
22											
23	**Total 2011 Forecast**	**$ 204**	**$ -**	**$ (21)**	**$ 5**	**$ (15)**	**$ (71)**	**$ (14)**	**$ 104**	**$ 154**	X-Ref - Section 9, Schedule 2.0

TG FORT NELSON

2011 REVENUE REQUIREMENT AND RATES APPLICATION

Cash Working Capital ($000s)

September 8, 2010

Line No.	Particulars	2009 Actual Normalized	2009 Decision	2010 Projected	2011 At Existing Rates	2011 Adjustment	2011 At Revised Rates	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Revenue Lead Days	34.9	34.7	34.9	38.5	0.0	38.5	Section 9, Schedule 7.2
2	Expense Lag Days	(37.2)	(37.6)	(37.0)	(32.1)	0.3	(31.9)	Section 9, Schedule 7.4
3	**Net (Lead) / Lag Days**	**(2.3)**	**(2.9)**	**(2.1)**	**6.3**	**0.3**	**6.6**	
4								
5	Cash Required for Operating Expenses	$ (33)	$ (51)	$ (31)	$ 92	$ 6	$ 97	
6	Minimum Cash Balance / Customer Deposits	(208)	(192)	(214)	-	-	-	
7								
8	Less Reserve for Bad Debts	(33)	(20)	(24)	(25)	-	(25)	
9	Withholdings from Employees	(16)	(15)	(18)	(18)	-	(18)	
10								
11	**Total Cash Working Capital**	**$ (290)**	**$ (277)**	**$ (287)**	**$ 49**	**$ 6**	**$ 54**	X-Ref - Section 9, Schedule 2.0

TG FORT NELSON

2011 REVENUE REQUIREMENT AND RATES APPLICATION

Lead Time from the Date of Payment to Receipt of Cash ($000s)

September 8, 2010

Line No.	Particulars	Revenue	Lead Days	Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)
1	**2009 Actual Normalized**				
2	Residential & Commercial	$ 5,009	34.6	$ 173,311	
3	Small Industrial	141	47.2	6,655	
4	**Total Sales / T-Service**	**5,150**	**34.9**	**179,966**	
5					
6	**Other Revenue**				
7	Late Payment Charge	22	26.7	587	
8	All Other	0	34.9	7	
9	Revenue from Service Work	10	41.9	411	
10	**Total**	**$ 5,182**	**34.9**	**$ 180,971**	
11					
12	**2009 Decision**				
13	Residential & Commercial	$ 5,854	34.6	$ 202,535	
14	Small Industrial	41	47.2	1,941	
15	**Total Sales / T-Service**	**5,895**	**34.7**	**204,476**	
16					
17	**Other Revenue**				
18	Late Payment Charge	27	26.7	724	
19	All Other	0	35.3	14	
20	Revenue from Service Work	17	41.9	716	
21	**Total**	**$ 5,939**	**34.7**	**$ 205,930**	

Lead Time from the Date of Payment to Receipt of Cash ($000s)

September 8, 2010

Line No.	Particulars	Revenue	Lead Days	Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)
1	**2010 Projected**				
2	Residential & Commercial	$ 4,576	34.6	$ 158,346	
3	Small Industrial	111	47.2	5,246	
4	**Total Sales / T-Service**	**4,688**	**34.9**	**163,592**	
5					
6	**Other Revenue**				
7	Late Payment Charge	28	26.7	751	
8	All Other	1	34.9	31	
9	Revenue from Service Work	15	41.9	620	
10	**Total**	**$ 4,731**	**34.9**	**$ 164,994**	
11					
12	**2011 Forecast at Existing Rates**				
13	Residential & Commercial	$ 4,519	38.3	$ 173,069	
14	Small Industrial	108	45.2	4,864	
15	**Total Sales / T-Service**	4,626	38.5	**177,933**	
16					
17	**Other Revenue**				
18	Late Payment Charge	38	38.3	1,465	
19	All Other	2	38.3	58	
20	Revenue from Service Work	20	38.3	757	
21	**Total**	**$ 4,686**	**38.5**	**$ 180,213**	
22					
23	**2011 Forecast at Revised Rates**				
24	Residential & Commercial	$ 4,793	38.3	$ 183,569	
25	Small Industrial	128	45.2	5,803	
26	**Total Sales / T-Service**	**4,921**	**38.5**	**189,372**	
27					
28	**Other Revenue**				
29	Late Payment Charge	38	38.3	1,465	
30	All Other	2	38.3	58	
31	Revenue from Service Work	20	38.3	757	
32	**Total**	**$ 4,981**	**38.5**	**$ 191,652**	X-Ref - Section 9, Schedule 7.0

Section 9
Schedule 7.3

Lag Time in Payment of Expenses ($000s)

September 8, 2010

Line No.	Particulars	Expense	Lag Days	Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)
1	**2009 Actual Normalized**				
2	Operating & Maintenance Expense	$ 658	19.3	$ 12,699	
3	Cost of Gas	3,764	40.7	153,191	
4					
5	Taxes other than income tax				
6	Property Taxes	157	4.0	628	
7	Goods & Service Tax (GST)	72	41.7	3,002	
8	S. S. Tax	247	43.8	10,819	
10	Carbon Tax	322	43.8	14,104	
11	Income Tax	21	15.2	319	
12	**Total Expense**	**$ 5,241**	**37.2**	**$ 194,762**	
13					
14	**2009 Decision**				
15	Operating & Maintenance Expense	$ 664	19.3	$ 12,807	
16	Cost of Gas	4,476	40.7	182,171	
17					
18	Taxes other than income				
19	Property Taxes	158	4.0	633	
20	Goods & Service Tax	278	41.7	11,608	
21	S. S. Tax	203	43.8	8,887	
22	Carbon Tax	426	43.8	18,648	
23	Income Tax	59	15.2	(790)	
24	**Total Expense**	**$ 6,264**	**37.6**	**$ 233,963**	

Lag Time in Payment of Expenses ($000s)

September 8, 2010

Line No.	Particulars	Expense	Lag Days	Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)
1	**2010 Projected**				
2	Operating & Maintenance Expense	$ 693	19.3	$ 13,375	
3	Cost of Gas	3,288	40.7	133,835	
4					
5	Taxes other than income				
6	Property Taxes	157	4.0	630	
7	Goods & Service Tax	118	41.7	4,933	
8	S. S. Tax	90	43.8	3,953	
9	Carbon Tax	512	43.6	22,310	
10	HST	356	41.7	14,860	
11	Income Tax	44	15.2	669	
12	**Total Expense**	**$ 5,259**	**37.0**	**$ 194,564**	
13					
14	**2011 Forecast at Existing Rates**				
15	Operating & Maintenance Expense	$ 698	25.5	$ 17,800	
16	Cost of Gas	3,179	40.2	127,779	
17					
18	Taxes other than income				
19	Property Taxes	165	2.0	330	
20	Carbon Tax	668	29.1	19,448	
21	HST	562	7.2	4,049	
22	Income Tax	5	15.2	76	
23	**Total Expense**	**$ 5,277**	**32.1**	**$ 169,483**	
24					
25					
26	Income Tax Expense	83	15.2	1,262	
27	**Total Expense at Revised Rates**	**$ 5,360**	**31.9**	**$ 170,744**	X-Ref - Section 9, Schedule 7.0

TG FORT NELSON

2011 REVENUE REQUIREMENT AND RATES APPLICATION

Other Working Capital - Inventories ($000s)

September 8, 2010

Line No.	Particulars	2009 Actual	2009 Decision	2010 Projected	2011 Forecast	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Pipe	$ 2	$ 2	$ 2	$ 2	
2	Fittings	10	1	1	1	
3	Regulators	-	-	-	-	
4	Supplies & Other	1	0	0	0	
5						
6	**Total Other Working Capital**	**$ 13**	**$ 3**	**$ 3**	**$ 3**	X-Ref - Section 9, Schedule 2.0

TG FORT NELSON Section 9

2011 REVENUE REQUIREMENT AND RATES APPLICATION Schedule 9.0

Utility Income and Earned Return ($000s)

September 8, 2010

Line No.	Particulars	2009 Actual Normalized	2009 Decision	2010 Projected	2011 @ Existing Rates	Adjustment	2011 @ Revised Rates	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Average No. of Customers**	2,355	2,356	2,365	2,377		2,377	Section 9, Schedule 10.1
2								
3	**Energy Volumes (TJ)**							
4	Sales	552	554	537	549		549	Section 9, Schedule 10.1
5	Transportation Service	69	14	52	50		50	Section 9, Schedule 10.1
6	**Total Energy Volumes (TJ)**	**621**	**568**	**589**	**598**	**-**	**598**	
7								
8	**Utility Revenue**							
9	Sales - Existing Rates	$ 5,009	$ 5,492	$ 4,576	$ 4,519		4,519	Section 9, Schedule 10.1
10	- Increase	-	361			274	274	Section 9, Schedule 10.1
11	- % Increase						6.1%	
12	Transportation - Existing Rates	141	31	111	108		108	Section 9, Schedule 10.1
13	- Increase	-	10	-		21	21	
14	**Total Revenue**	**5,150**	**5,895**	**4,688**	**4,626**	**295**	**4,921**	
15	Cost of Gas Sold (including Gas Lost)	3,764	4,476	3,288	3,179		3,179	Section 9, Schedule 10.1
16	Gross Margin	1,386	1,419	1,399	1,448	295	1,743	
17	RSAM Revenue	(86)	-	52	-		-	
18	**Adjusted Gross Margin**	**1,300**	**1,419**	**1,451**	**1,448**	**295**	**1,743**	
19								
20	Operating & Maintenance Expense	658	664	693	698		698	Section 9, Schedule 12.0
21	Property Tax	157	158	157	165		165	Section 9, Schedule 13.0
22	Depreciation & Amortization Expense	162	191	187	355		355	Section 9, Schedule 14.0
23	Other Operating Revenue	(32)	(45)	(44)	(60)		(60)	Section 9, Schedule 11.0
24	**Total Utility Expenses**	**945**	**968**	**993**	**1,159**	**-**	**1,159**	
25								
26	Utility Income Before Income Tax	355	451	458	289	295	584	
27	Income Tax Expense	21	59	44	5	78	83	Section 9, Schedule 15.0
28								
29	**Earned Return**	**$ 334**	**$ 392**	**$ 414**	**$ 284**	**$ 217**	**$ 501**	X-Ref - Section 9, Schedule 15.0
30								
31	**Utility Rate Base**	**$ 5,055**	**$ 5,405**	**$ 5,320**	**$ 6,565**	**$ 6**	**$ 6,571**	Section 9, Schedule 2.0, 15.4
32								
33	**Return on Rate Base**	**6.60%**	**7.25%**	**7.77%**	**4.32%**		**7.62%**	Section 9, Schedule 15.5

TG FORT NELSON

2011 REVENUE REQUIREMENT AND RATES APPLICATION

Margin ($000s)

September 8, 2010

Line No.	Particulars	Average # of Customers	Volume (TJ)	Ave. Bundled Rate	Revenue	Ave. Cost of Gas	Cost of Gas	Ave. Margin	Margin	Ave. Increase	Increase / (Decrease)	Ave. Revised Sales Rate	Revised Revenue	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	**2009 Actual Normalized**													
2	**Sales**													
3	Residential	1,914.0	267.0	$ 8.956	$ 2,391.2	$ 6.779	$ 1,810.1	$ 2.176	$ 581.1					
4	General Service Rate 2.1	411.0	191.0	$ 9.313	$ 1,778.7	$ 6.810	$ 1,300.8	$ 2.502	477.9					
5	General Service Rate 2.2	28.0	94.0	$ 8.929	$ 839.3	$ 6.876	$ 646.3	$ 2.053	193.0					
6	**Total**	**2,353.0**	**552.0**		**5,009.2**		**3,757.2**		**1,252.0**					
7														
8	General Firm T-Service	2.0	69.0	$ 2.038	140.6	$ 0.097	6.7	$ 1.941	133.9					
9														
10	**Total**	**2,355.0**	**621.0**		**$ 5,149.8**		**$ 3,763.9**		**$ 1,385.9**					
11														
12	**2009 Decision**													
13	**Sales**													
14	Residential	1,915.0	270.5	$ 10.503	2,841.0	$ 8.077	2,184.9	$ 2.425	$ 656.1					
15	General Service Rate 2.1	411.0	195.0	$ 10.781	2,102.2	$ 8.080	1,575.5	$ 2.701	526.7					
16	General Service Rate 2.2	28.0	88.4	$ 10.299	910.4	$ 8.079	714.2	$ 2.220	196.2					
17	**Total**	**2,354.0**	**553.9**		**5,853.6**		**4,474.6**		**1,379.0**					
18														
19	General Firm T-Service	2.0	13.8	$ 2.985	41.1	$ 0.096	1.3	$ 2.889	39.8					
20														
21	**Total**	**2,356.0**	**567.7**		**5,894.7**		**4,475.9**		**$ 1,418.8**					

Margin ($000s)

Line No.	Particulars	Average # of Customers	Volume (TJ)	Ave. Bundled Rate	Revenue	Ave. Cost of Gas	Cost of Gas	Ave. Margin	Margin	Ave. Increase	Increase / (Decrease)	Ave. Revised Sales Rate	Revised Revenue	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	**2010 Projected**													
2	**Sales**													
3	Residential	1,923.0	256.6	$ 8.389	2,152.6	$ 6.094	1,563.6	$ 2.295	$ 588.9					
4	General Service Rate 2.1	412.0	187.9	$ 8.807	1,654.8	$ 6.159	1,157.2	$ 2.648	497.6					
5	General Service Rate 2.2	28.0	92.4	$ 8.328	769.2	$ 6.081	561.6	$ 2.247	207.5					
6	**Total**	**2,363.0**	**536.8**		**4,576.5**		**3,282.4**		**1,294.0**					
7														
8	General Firm T-Service	2.0	52.0	$ 2.139	111.1	$ 0.114	5.9	$ 2.025	105.2					
9														
10	**Total**	**2,365.0**	**588.8**		**$ 4,687.6**		**$ 3,288.3**		**$ 1,399.3**					
11														
12	**2011 Forecast**													
13	**Sales**													
14	Residential	1,932.0	263.4	$ 8.112	2,136.7	$ 5.784	1,523.5	$ 2.328	$ 613.2	$ 0.474	124.9	$ 8.586	2,261.7	
15	General Service Rate 2.1	415.0	190.8	$ 8.494	1,620.5	$ 5.784	1,103.5	$ 2.710	517.0	$ 0.552	105.3	$ 9.046	1,725.8	
16	General Service Rate 2.2	28.0	94.4	$ 8.068	761.5	$ 5.784	546.0	$ 2.284	215.6	$ 0.465	43.9	$ 8.533	805.5	
17	**Total**	**2,375.0**	**548.6**		**4,518.8**		**3,173.0**		**1,345.8**		**274.1**		**4,792.9**	X-Ref - Section 9, Schedule 1.0, 9.0
18														
19	General Firm T-Service	2.0	49.5	$ 2.172	107.6	$ 0.113	5.6	$ 2.059	102.0	$ 0.419	20.8	$ 2.591	128.4	X-Ref - Section 9, Schedule 1.0, 9.0
20														
21	**Total**	**2,377.0**	**598.1**		**$ 4,626.4**		**$ 3,178.6**		**$ 1,447.8**		**$ 294.9**		**$ 4,921.3**	X-Ref - Section 9, Schedule 1.0, 9.0
22														
23	**Total Deficiency / (Surplus)**										**$ 294.9**			
24														
25	**% Increase / (Decrease)**										**6.37%**			X-Ref - Section 9, Schedule 1.0

TG FORT NELSON

2011 REVENUE REQUIREMENT AND RATES APPLICATION

Other Revenue ($000s)

September 8, 2010

Line No.	Particulars	2009 Actual	2009 Decision	2010 Projected	2011 Forecast	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Late Payment Charge	$ 22	$ 27	$ 28	$ 38	
2						
3	Revenue form Service Work	10	17	15	20	
4						
5	All Other	0	0	1	2	
6						
7	**Total Other Revenue**	**$ 32**	**$ 45**	**$ 44**	**$ 60**	X-Ref - Section 9, Schedule 1.0, 9.0

Operating & Maintenance Expenses ($000s)

Line No.	Particulars	2009 Actual	2009 Decision	2010 Projected	2011 Forecast	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**RESOURCE VIEW**					
2	M&E Costs	$ 128	$ 145	$ 136	$ 141	
3	COPE Costs	55	53	63	68	
4	IBEW Costs	262	247	255	258	
5	**Total Labour Costs**	**445**	**444**	**455**	**467**	
6						
7	Vehicle Costs	65	59	54	61	
8	Employee Expenses	13	33	37	17	
9	Materials	14	23	29	14	
10	Computer Costs	24	24	31	34	
11	Fees & Administration Costs	57	62	60	60	
12	Contractor Costs	168	166	171	177	
13	Facilities	39	29	32	42	
14	Recoveries & Revenue	(41)	(49)	(62)	(56)	
15	HST Savings	-	-	(1)	(3)	
16	**Total Non-Labour Costs**	**339**	**346**	**351**	**345**	
17						
18	**Total Gross O&M Expenses**	**784**	**790**	**806**	**812**	
19						
20	Less Capitalized Overhead	(126)	(126)	(113)	(114)	
21						
22	**Total Net O&M Expenses**	**$ 658**	**$ 664**	**$ 693**	**$ 698**	X-Ref - Section 9, Schedule 1.0, 9.0

Operating & Maintenance Expenses ($000s)

September 8, 2010

Line No.	Particulars	2009 Actual	2009 Decision	2010 Projected	2011 Forecast	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**ACTIVITY VIEW**					
2	Distribution Supervision	$ 185	$ 182	$ 191	$ 192	
3	**Distribution Supervision Total**	**185**	**182**	**191**	**192**	
4						
5	Operation Centre - Distribution	124	124	128	129	
6	Asset Management - Distribution	21	20	22	22	
7	Preventative Maintenance - Distribution	42	30	43	44	
8	Distribution Operations - General	100	88	103	104	
9	Emergency Management	117	152	121	122	
10	**Distribution Operations Total**	**404**	**413**	**417**	**420**	
11						
12	Distribution Corrective - Meters	25	22	26	26	
13	Distribution Corrective - Propane	-	-	-	-	
14	Distribution Corrective - Leak Repair	21	21	22	22	
15	Distribution Corrective - Stations	12	11	12	12	
16	Distribution Corrective - General	5	7	5	5	
17	**Distribution Maintenance Total**	**63**	**61**	**65**	**66**	
18						
19	**Distribution Total**	**652**	**656**	**672**	**678**	
20						
21	Customer Contact - ABSU Contract	132	134	134	136	
22	**Customer Care Total**	**132**	**134**	**134**	**136**	
23						
24	Less: HST Savings	-	-	(1)	(3)	
25						
26	**Total Gross O&M Expense**	**784**	**790**	**806**	**812**	
27						
28	Less: Capitalized Overhead	(126)	(126)	(113)	(114)	
29						
30	**Total Net O&M Expenses**	**$ 658**	**$ 664**	**$ 693**	**$ 698**	X-Ref - Section 9, Schedule 1.0, 9.0

TG FORT NELSON

2011 REVENUE REQUIREMENT AND RATES APPLICATION

Property Tax ($000s)

September 8, 2010

Line No.	Particulars	2009 Actual	2009 Decision	2010 Projected	2011 Forecast	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	General, School & Other	$ 103	$ 104	$ 102	$ 108	
2	1% in Lieu of General	54	54	55	58	
3						
4	**Total Property Tax**	**$ 157**	**$ 158**	**$ 157**	**$ 165**	X-Ref - Section 9, Schedule 1.0, 9.0

TG FORT NELSON

2011 REVENUE REQUIREMENT AND RATES APPLICATION

Depreciation & Amortization Expense ($000s)

September 8, 2010

Line No.	Particulars	2009 Actual	2009 Decision	2010 Projected	2011 Forecast	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Depreciation Provision**					
2	Transmission	$ 23	$ 26	$ 53	$ 62	Section 9, Schedule 4.2
3	Distribution	133	146	187	202	Section 9, Schedule 4.2
4	General	14	35	35	49	Section 9, Schedule 4.2
5	**Total Depreciation Provision**	**171**	**207**	**274**	**313**	
6						
7	Less: Amortization of CIAOC	(24)	(22)	(89)	(29)	Section 9, Schedule 5.1
8						
9	**Total Depreciation Expense**	**147**	**185**	**186**	**284**	X-Ref - Section 9, Schedule 1.0, 15.1
10						
11	Amortization Expense	15	6	1	71	X-Ref - Section 9, Schedule 1.0, 15.1
12						
13	**Total Depreciation & Amortization Expense**	**$ 162**	**$ 191**	**$ 187**	**$ 355**	X-Ref - Section 9, Schedule 9.0

Income Tax ($000s)
September 8, 2010

Line No.	Particulars	2009 Actual Normalized	2009 Decision	2010 Projected	2011 @ Existing Rates	Adjustment	2011 @ Revised Rates	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Earned Return	$ 334	$ 392	$ 414	$ 284	$ 217	$ 501	Section 9, Schedule 9.0
2	Less: Interest on Debt	(222)	(232)	(215)	(251)	(0)	(251)	Section 9, Schedule 15.4
3	Add: Non-Tax Deductible Expense (Net)	17	6	3	74	-	74	Section 9, Schedule 15.1
4	Less: Timing Differences	(80)	(27)	(91)	(94)	-	(94)	Section 9, Schedule 15.1
5								
6	**Taxable Income after Tax**	**$ 49**	**$ 139**	**$ 111**	**$ 13**	**$ 217**	**$ 230**	
7								
8	**Taxable Income**	**$ 70**	**$ 198**	**$ 155**	**$ 18**	**$ 295**	**$ 313**	
9								
10	Income Tax Rate	30.0%	30.0%	28.5%	26.5%		26.5%	
11	1 - Current Tax Rate	70.0%	70.0%	71.5%	73.5%		73.5%	
12								
13	Income Tax							
14	Current	$ 21	$ 59	$ 44	$ 5	$ 78	$ 83	X-Ref - Section 9, Schedule 1.0, 9.0
16		-	-	-	-		-	
17								
18	**Total Income Taxes**	**$ 21**	**$ 59**	**$ 44**	**$ 5**	**$ 78**	**$ 83**	X-Ref - Section 9, Schedule 1.0, 9.0

Permanent & Timing Differences ($000s)

September 8, 2010

Line No.	Particulars	2009 Actual	2009 Decision	2010 Projected	2011 Forecast	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Permanent Differences**					
2	Non-tax Deductible Expenses	2	-	3	3	
3	Deferred Amortization Expenses	15	6	1	71	Section 9, Schedule 14.0
4	**Total Permanent Differences**	**$ 17**	**$ 6**	**$ 3**	**$ 74**	X-Ref - Section 9, Schedule 15.0
5						
6	**Timing Differences**					
7	Depreciation Expense	$ 147	$ 185	$ 186	$ 284	Section 9, Schedule 14.0
8	Amortization of Debt Issue Expenses for Accounting	2	1	4	4	
9	Debt Issue Costs / Discounts for Tax Purposes	(6)	-	(6)	(5)	
10	Capital Cost Allowance (CCA)	(153)	(166)	(190)	(290)	Section 9, Schedule 15.3
11	Cumulative Eligible Capital Allowance	-	-	-	-	
12	Overheads Capitalized for Tax Purposes	(39)	(47)	(48)	(49)	
13	Pension Reserve	(31)	-	(36)	(38)	
14	**Total Timing Differences**	**$ (80)**	**$ (27)**	**$ (91)**	**$ (94)**	Section 9, Schedule 15.0

TG FORT NELSON Section 9

2011 REVENUE REQUIREMENT AND RATES APPLICATION Schedule 15.2

Capital Cost Allowance Continuity ($000s)

September 8, 2010

Line No.	Class	CCA Rate %	UCC Opening Balance	Opening Adjustments	Adjusted UCC Opening	Additions	1/2 Year Adjustment	Adjusted UCC	CCA	UCC Closing Balance	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(6)	(10)	(11)
1	**2009 Actual**										
2	1	4%	$ 3,206	$ (310)	$ 2,896	$ -	$ -	$ 2,896	$ (116)	$ 2,780	
3	2	6%	347		347	-	-	347	(21)	326	
4	8	20%	5	-	5	-	-	5	(1)	4	
5	10	30%	6	-	6	-	-	6	(2)	4	
6	13	manual	3	-	3	-	-	3	(1)	2	
7	3	5%	17	-	17	-	-	17	(1)	16	
8	6	10%	1	-	1	-	-	1	-	1	
9	1.3	6%	-	11	11	-	-	11	(1)	10	
10	47	8%	-	-	-	.	-	-	-	-	
11	51	6%	-	(1)	(1)	330	(165)	164	(10)	319	
12	50	55%	-	-	-	-	-	-	-	-	
13	7	15%	-	-	-	-	-	-	-	-	
14	49	8%	8	3	11	-	-	11	(1)	10	
15	12	100%	-	-	-	-	-	-	-	-	
16	**Total**		**$ 3,593**	**$ (297)**	**$ 3,296**	**$ 330**	**$ (165)**	**$ 3,461**	**$ (154)**	**$ 3,473**	
17											
18	**2009 Decision**										
19	1	4%	$ 3,219	$ -	$ 3,219	$ 277	$ (139)	$ 3,358	$ (134)	$ 3,362	
20	2	6%	347	-	347	-	-	347	(21)	326	
21	3	5%	17	-	17	-	-	17	(1)	16	
22	6	10%	1	-	1	-	-	1	-	1	
23	8	20%	29	-	29	11	(6)	34	(7)	33	
24	10	30%	8	-	8	-	-	8	(2)	6	
25	12	100%	-	-						-	
26	13	manual	1	-	1	-	-	1	(1)	(0)	
27	45	45%	1		1	-	-	1	-	1	
28	49	8%	6	-	6	-	-	6	-	6	
29	**Total**		**$ 3,629**	**$ -**	**$ 3,629**	**$ 288**	**$ (144)**	**$ 3,774**	**$ (166)**	**$ 3,752**	

Capital Cost Allowance Continuity ($000s)

Line No.	Class	CCA Rate %	UCC Opening Balance	Opening Adjustments	Adjusted UCC Opening	Additions	1/2 Year Adjustment	Adjusted UCC	CCA	UCC Closing Balance	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(6)	(10)	(11)
1	**2010 Projected**										
2	1	4%	$ 2,780	$ -	$ 2,780	$ -	$ -	$ 2,780	$ (111)	$ 2,669	
3	2	6%	326	-	326	-	-	326	(20)	306	
4	8	20%	4	-	4	8	(4)	8	(2)	10	
5	10	30%	4	-	4	-	-	4	(1)	3	
6	13	manual	2	-	2	-	-	2	(1)	1	
7	3	5%	16	-	16	-	-	16	(1)	15	
8	6	10%	1	-	1	-	-	1	-	1	
9	1.3	6%	10	44	54	468	-	522	(31)	491	
10	47	8%	-	-	-	-	-	-	-	-	
11	51	6%	319	(232)	87	202	(101)	188	(11)	278	
12	50	55%	-	-	-	-	-	-	-	-	
13	7	15%	-	-	-	-	-	-	-	-	
14	49	8%	10	141	151	10	(5)	156	(12)	149	
15	12	0%	-	-	-	-	-	-	-	-	
16	**Total**		**$ 3,473**	**$ (47)**	**$ 3,425**	**$ 689**	**$ (110)**	**$ 4,003**	**$ (190)**	**$ 3,924**	
17											
18	**2011 Forecast**										
19	1	4%	$ 2,669	$ -	$ 2,669	$ -	$ -	$ 2,669	$ (107)	$ 2,562	
20	2	6%	306	-	306	-	-	306	(18)	288	
21	8	20%	10	-	10	8	(4)	14	(3)	15	
22	10	30%	3	-	3	-	-	3	(1)	2	
23	13	manual	1	-	1	-	-	1	(1)	(0)	
24	3	5%	15	-	15	-	-	15	(1)	14	
25	6	10%	1	-	1	-	-	1	-	1	
26	1.3	6%	491	-	491	-	-	491	(29)	462	
27	47	8%	-	-	-	-	-	-	-	-	
28	51	6%	278	-	278	193	(97)	375	(22)	449	
29	50	55%	-	-	-	-	-	-	-	-	
30	7	15%	-	-	-	-	-	-	-	-	
31	49	8%	149	-	149	2,410	(1,205)	1,354	(108)	2,451	
32	12	100%	-	-	-	-	-	-	-	-	
33	**Total**		**$ 3,924**	**$ -**	**$ 3,924**	**$ 2,612**	**$ (1,306)**	**$ 5,229**	**$ (290)**	**$ 6,245**	X Ref - Section 9, Schedule 15.1

TG FORT NELSON

2011 REVENUE REQUIREMENT AND RATES APPLICATION

Interest Expense ($000s)

September 8, 2010

Line No.	Particulars	2009 Actual Normalized	2009 Decision	2010 Projected	2011 @ Existing Rates	Adjustment	2011 @ Revised Rates	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Utility Rate Base	$ 5,055	$ 5,405	$ 5,320	$ 6,565	$ 6	$ 6,571	Section 9, Schedule 2.0, 9.0
2								
3	Weighted average embedded cost of debt in the capital structure							
4	Long-term debt	4.180%	3.909%	3.845%	3.187%	-0.003%	3.185%	Section 9, Schedule 15.5
5	Unfunded debt	0.210%	0.376%	0.200%	0.635%	0.002%	0.637%	Section 9, Schedule 15.5
6	**Total**	**4.390%**	**4.285%**	**4.044%**	**3.822%**	**-0.001%**	**3.821%**	
7								
8	**Utility Interest Expense**	**$ 222**	**$ 232**	**$ 215**	**$ 251**	**$ (0)**	**$ 251**	X-Ref - Section 9, Schedule 1.0, 15.0

Return on Capital ($000s)

Line No.	Particulars		Amount	Capitalization %	Embedded Cost %	Cost Component	Earned Return	Reference
	(1)		(2)	(3)	(4)	(5)	(6)	(7)
1	**2009 Actual Normalized**							
2	Unfunded Debt		$ 250	4.95%	4.250%	0.210%	$ 11	
3	Long Term Debt		3,035	60.04%	6.962%	4.180%	211	
4	Common Equity		1,770	35.01%	6.312%	2.210%	112	
5		**Total**	**$ 5,055**	**100.00%**		**6.600%**	$ 334	
6								
7	**2009 Decision (Order No. G-172-08)**							
8	Unfunded Debt		$ 478	8.84%	4.250%	0.376%	$ 20	
9	Long Term Debt		3,035	56.15%	6.962%	3.909%	211	
10	Common Equity *		1,892	35.01%	8.470%	2.965%	160	
11		**Total**	**$ 5,405**	**100.00%**		**7.250%**	$ 392	
12								
13	**2010 Projected**							
14	Unfunded Debt		$ 250	4.70%	4.250%	0.200%	$ 11	
15	Long Term Debt **		2,942	55.30%	6.952%	3.845%	205	
16	Common Equity		2,128	40.00%	9.321%	3.729%	198	
17		**Total**	**$ 5,320**	**100.00%**		**7.773%**	$ 414	
18								
19	**2011 @ Existing Rates**							
20	Unfunded Debt		$ 926	14.11%	4.500%	0.635%	$ 42	
21	Long Term Debt **		3,013	45.89%	6.945%	3.187%	209	
22	Common Equity		2,626	40.00%	1.254%	0.501%	33	
23		**Total**	**$ 6,565**	**100.00%**		**4.324%**	$ 284	
24								
25	**2011 @ Revised Rates**							
26	Unfunded Debt Adjusted		$ 929	14.14%	4.500%	0.637%	$ 42	X-Ref - Section 9, Schedule 15.4
27	Long Term Debt **		3,013	45.86%	6.945%	3.185%	209	X-Ref - Section 9, Schedule 15.4
28	Common Equity		2,628	40.00%	9.500%	3.800%	250	X-Ref - Section 9, Schedule 1.0, 9.0
29		**Total**	**$ 6,571**	**100.00%**		**7.621%**	$ 501	X-Ref - Section 9, Schedule 1.0, 9.0

* ROE adjusted to 8.99% as per Commission Order No. G-158-09
** Long Term Debt as per TGI BCUC Order No. G-158-09; Schedule 65, Section 13, line 25

10 APPROVALS SOUGHT AND PROPOSED REGULATORY PROCESS

In this section, TG Fort Nelson identifies the approvals sought in this Application, and the proposed regulatory process. Appendix D contains a Draft form of Order.

10.1 Approvals Sought

In summary, TG Fort Nelson is forecasting a revenue deficiency in 2011 of $295 thousand. The Company seeks the following approvals from the Commission, pursuant to Sections 58, 60, and 61 of the *Utilities Commission Act* (the "Act"):

- To allow TG Fort Nelson to recover the revenue deficiency of $295 thousand through a permanent increase in its delivery rates, effective January 1, 2011.
- A margin increase of 20.37 per cent and revised rates as per Section 2.4 Tables 2-2 and 2-3.
- The RSAM rider to be set to $0.033 (a decrease of $0.004) as per Section 2.3.1 Table 2-4 effective January 1, 2011.
- Approval of the continuation of the following deferral accounts, as described in Section 7.6:
  - Gas Cost Reconciliation Account (GCRA);
  - Revenue Stabilization Adjustment Mechanism (RSAM) and RSAM Interest;
  - Property Tax Deferral;
  - Deferred Interest;
  - 2009 and 2010 ROE & Capital Structure Deferral Account, with full amortization in 2011; and
  - 2010 IFRS Transitional Deferral.
- Approval of the following new deferral account as described in Section 7.6:
  - 2011 RRA Costs Deferral
- Adoption of the following Accounting and Other Policy Changes approved in the Terasen Gas Inc. 2010-2011 Negotiated Settlement Agreement:
  - Depreciation rates as set out in Section 7 Table 7-6 and Section 9 Schedule 4.2;
  - An overheads capitalized rate of 14 per cent of Gross O&M;
  - Training and Feasibility Study Costs to be treated as O&M expense, rather than capital;

- All capital expenditures to be included in plant in service (and rate base) in the month following the available-for-use date, with depreciation starting at that time; and
- Adoption of the Cash Working Capital Lead/Lag Days as set out Section 7 Table 7-7.

TG Fort Nelson also requests acceptance of the Muskwa River Crossing Project under Section 44.2 of the Act, as described in Section 7.3.2.

10.2 Proposed regulatory process

Appendix D contains a Draft Procedural Order. TG Fort Nelson is of the view that a written hearing process is appropriate for the review of this Application, and proposes the following regulatory timetable:

ACTION	DATE (2010)
Publication of Notice	October 4 to October 15
Commission Information Request No. 1	Wednesday, October 6
Intervenor Registration	Friday, October 8
Intervenor Information Request No. 1	Wednesday, October 13
TG Fort Nelson Response to Information Requests No. 1	Thursday, November 10
TG Fort Nelson Final Argument Submissions	Thursday, November 18
Intervenor Final Argument Submissions	Thursday, November 25
TG Fort Nelson Reply Argument Submissions	Thursday, December 2

Should the Commission be unable to render its decision in this Application respecting TG Fort Nelson permanent rates in time to be effective January 1, 2011, TG Fort Nelson hereby requests approval pursuant to Section 89 of the Act of the rates sought in this Application on an interim basis, effective January 1, 2011.

11 GLOSSARY OF TERMS

AFUDC

Allowance for Funds Used During Construction, which is an allowance for the cost of debt and equity funding of capital projects before they are completed and placed into service and included in rate base; the AFUDC recorded for a project is added to the overall project cost.

Contribution In Aid of Construction ("CIAC")

A cash injection by a customer(s) towards a project that is related to their service request.

Commission

British Columbia Utilities Commission, the provincial body regulating utilities in British Columbia. Also known as the BCUC.

CMHC

Canada Mortgage and Housing Corporation, Canada's national housing agency.

Deferred Costs (or Charges)

Operating and maintenance costs that are incurred but that will be expensed in the future.

GCRA – Gas Cost Reconciliation Accounts

A deferral account used to record variances between the TG Fort Nelson forecast and actual gas purchase costs. GCRA balances are either recovered through rates or refunded to customers in subsequent years through the GCRA rider.

GJ – Gigajoule

A measure of energy of natural gas equal to one billion joules, used for billing purposes. One gigajoule (GJ) is equivalent to approximately 278 kilowatt hours of electricity or 28.85 litres of gasoline.

Revenue Requirement

The total amount of money a utility must collect from customers to pay all operating and capital costs, including a fair return on investment.

Rider

A temporary adjustment to rates usually reflecting the disposition of deferral account balances.

RSAM

Rate Stabilization Adjustment Mechanism (RSAM) is a deferral account used to record variances between forecast and actual core market and industrial margins resulting from changes in use per customer from factors such as colder or warmer than normal temperature. RSAM balances are either recovered through rates or refunded to customers in subsequent years through the RSAM rider.

TJ – Terajoule

One million million joules (10^{12}).

Transportation Service

Gas delivery service provided by Terasen Gas to customers who purchase natural gas directly from producers or marketers (customers served under Rate Schedule 25 within TG Fort Nelson).

UAF

UAF refers to gas that is not specifically accounted for in gas energy balance of receipts, deliveries, and operations use.

Appendix A

TP168.3mm MUSKWA RIVER CROSSING FRONT END ENGINEERING DESIGN

TP168.3mm Muskwa River Crossing

Front End Engineering Design
(FID 32004)

Prepared for Terasen Gas Inc.
By David Bainbridge, P.Eng

1	10.09.03	Re-Issued for Use	DGB						
0	10.03.05	Issued for Use	DGB	DE					
B1	10.02.10	Issued for Client Review	DGB	DE					
A1	09.11.28	Issued for Internal Review	DGB						
Rev.	Date (yy.mm.dd)	Issue	Originator	Checked	Discipline Lead	Project Lead	Engineering Manager	Project Manager	Client

CHINOOK Document	09-312-PL-15-01
Client Document No.	32004.0901
Revision No.	1
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Appendix D Option 3 Front End Engineering and Design
Appendix E Option 4 Front End Engineering and Design
Appendix F Option Comparison and Evaluation

1. Summary

1.1 Project Description

The 168mm O.D. Fort Nelson transmission lateral crosses the Muskwa River at kilometre post 17+300 and is presently at risk due to severe channel scour as the pipeline is exposed at the thalweg of the watercourse. Immediate action is required, as the risk to the pipeline has been classified as High according to the Terasen Geotechnical Hazards Database. This Front End Engineering Design (FEED) study has been commissioned to propose and evaluate a number of options to reconcile the risk and repair or replace the crossing.

1.2 FEED Objectives

The objective of this FEED study is to define and evaluate a number of possible construction solutions to replace or repair the existing exposed 168mm O.D. Muskwa River pipeline crossing. The objective includes to:

- Describe the present condition of the crossing and the present risks incident on the exposed pipe;
- Describe and evaluate all construction options in terms of cost, constructability, risk, lands, schedule and environmental impact;
- Recommend a preferred course of action based on a comparison of the aforementioned metrics.

1.3 Overview of Remediation Options

The following options are proposed as feasible and are evaluated within this study:

- Option No. 1: A 168mm O.D. Horizontal Directional Drill (HDD) crossing of the Muskwa River to replace and abandon the existing crossing;
- Option No. 2: A 168mm O.D. Open Cut crossing (without isolation) of the Muskwa River to replace and abandon the existing at risk crossing;

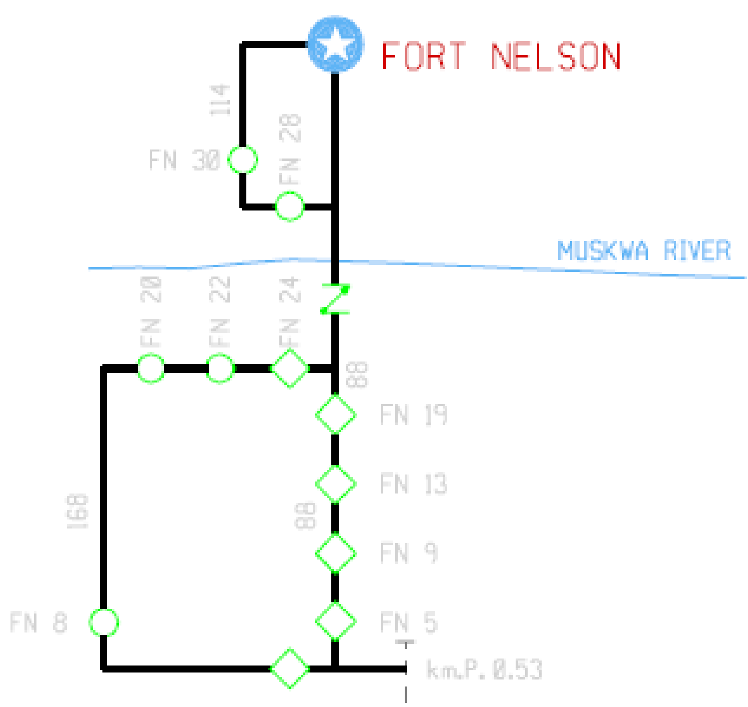
- Option No. 3: In stream alteration of the existing 168mm O.D. crossing in order to lower the pipeline and install rip-rap protection along the stream bed;

- Option No. 4: Installation of a new Fort Nelson TP/IP Gate Station on the upstream bank (uplands) of the Muskwa River to replace the existing TP/IP portion of the Fort Nelson Gate Station located immediately downstream of the river crossing (kp 18+740), and installation of a steel IP168mm pipeline fixed to the Hwy #97 bridge to cross the river.

1.4 Project Location

The Muskwa River crossing is located approximately 3 km (by road) southeast of Fort Nelson in British Columbia. The pipeline crosses the river about 75 m upstream of the Alaskan Highway (#97) bridge outside Fort Nelson. At the crossing location, the Muskwa River flows southwest to northeast and meanders irregularly. There is a slight bend in the channel at the crossing reach. An oxbow is located about 2.5 km downstream of the crossing. Figure 1 shows a schematic of the Fort Nelson transmission pipeline system.

Figure 1: FN Transmission System Schematic



2. Present Asset Condition

The crossing reach is mildly sloped (0.04%), relatively wide (180 m), and single-threaded. Considerable bank erosion on the north bank spans at least 200 m along the channel, crossing over the pipe. A large gravel and sand bar is located on the south bank, which is used for launching boats. On the southeast side of this bar, a topographic low is occupied during high flows, forming a high water channel.

A survey of the Muskwa River crossing was conducted on September 28, 2008 by Midwest Surveys. The surveyed profile is attached in Appendix A as a part of the BGC Engineering assessment. The survey indicates that there is approximately 12 metres of exposed pipe on the north side of the channel, near the thalweg. The flow is constricted by the gravel bar attached to the south bank. The deepest part of a significant scour hole, that is about 1.2 m deeper than the average grade of the bed, is located 30 m upstream of the pipeline. The pipeline crosses this scour hole where it is about 0.7 m below the average bed grade. Depth of cover is generally shallow across the whole crossing, including under the south bank gravel and sand bar. The minimum depth of cover in the secondary channel is 0.36 m. This was the first depth of cover survey that has been conducted at this location. Wetted width of the channel is approximately 100 metres.

Bank erosion persists along the north bank, which is commensurate with the meandering channel plan and the existence of the large bar on the south bank that diverts the flow to the north. Scour at the channel north is also due to the effect of spiralling flow concentration on the outside edge of the meander.

3. Project Historical Information

A general history of the pipeline installation, based on regulatory filings, is as follows:

- 1960 – Original Fort Nelson pipeline is installed under Oil and Gas Commission Certificate 59, Project 1068. The original Muskwa River crossing was a 4” aerial bridge crossing;

- 1973 – Determined that the Alaska Highway (#97) Bridge of the Muskwa River is to be replaced with a new highway bridge. Fort Nelson Gas Ltd decides to remove the existing 4” crossing from the bridge and replace it with a new 6” open cut crossing of the river immediately upstream of the old bridge to be removed and replaced;

- 1974 – A new 6” river crossing is installed across the Muskwa River. The crossing is installed by open cut methods and the pipe is coated in yellow jacket and is wrapped in 1” thick spruce lumber in order to be dragged into place. Full encirclement river weights are placed on the pipeline for buoyancy control. Schedule 80 pipe is installed under the river and schedule 40 pipe is installed along the approaches and banks of the river;

- 2008 – Field survey conducted along the river crossing determines that the line is exposed for 12m at the thalweg of the watercourse.

4. Scope of Work

4.1 Stream Characteristics

The Muskwa River is within the McKenzie River basin in northeastern British Columbia and has an assumed BC Riparian Class of S1-B; meaning the active flood plain is assumed to be a function of the stream channel dimensions (channel width is greater than 100m wide). As an S1 classified watercourse, the watercourse is ranked as having high fish and fish habitat value with the following riparian areas:

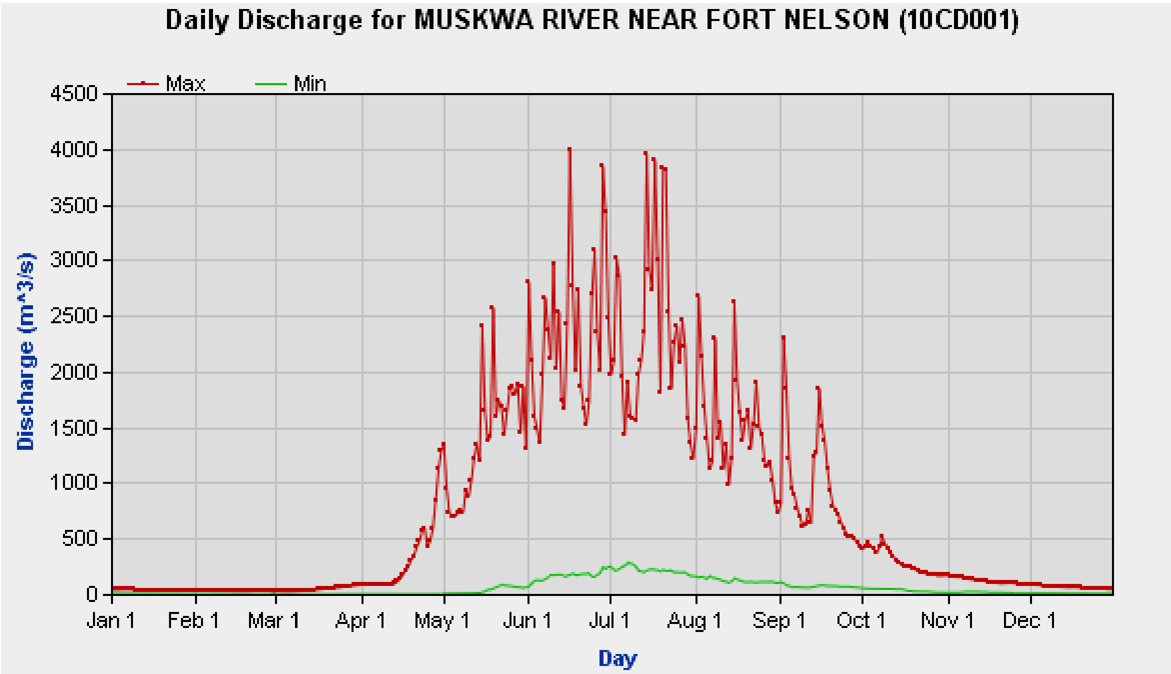
- Riparian Management Area of 70 m;

- Riparian Reserve Zone of 50 m;

- Riparian Management Zone of 20 m.

The Muskwa River has a mean annual flow rate of 215 m3/s and river hydrology data can be found in Appendix A. Water survey of Canada daily discharge data is seen in Figure 2.

Figure 2: Water Survey of Canada daily data for the Muskwa River



In BC, detailed information regarding fish distribution and lake and stream information is available on Fish Wizard (BC Ministry of Forests 2007) and includes known presence of fish species of particular conservation concern as well as other sport, coarse, and forage fishes. Figure 3 shows the species from Fish Wizard that are known to occupy the Muskwa River. The Muskwa River is classified as an S1 fish-bearing watercourse with a window for instream work from July 15th to August 15th (Figure 5).

A fisheries site assessment is yet to occur but based on interpretation of available pictures, it may be assumed that the habitat potential can be characterized as moderate to high for sport fish. Summer feeding and rearing habitat quality is assumed to be moderate given large woody debris and moderate overhanging vegetation along portions of channel margins. No overhanging vegetation could be seen over channel depths. Wintering potential is also assumed high given open-water depth. Migration appears to be unimpeded in the project area.

Figure 3: Fish Species Identified to Occupy the Muskwa River in Fish Wizard

BC Code	Common Name	Scientific Name
GR	Arctic Grayling	Thymallus arcticus
BT	Bull Trout	Salvelinus confluentus
BB	Burbot	Lota lota
	Chum Salmon	-
	Dolly Varden	-
	Finescale Dace	-
	Flathead Chub	-
	Inconnu	-
LKC	Lake Chub	Couesius plumbeus
CSU	Largescale Sucker	Catostomus macrocheilus
LNC	Longnose Dace	Rhinichthys cataractae
LSU	Longnose Sucker	Catostomus catostomus
MW	Mountain Whitefish	Prosopium williamsoni
NP	Northern Pike	Esox lucius
CCG	Slimy Sculpin	Cottus cognatus
CRI	Spoonhead Sculpin	Cottus ricei
	Sucker (General)	-
	Troutperch	-
	Walleye	-
WSU	White Sucker	Catostomus commersonii

4.2 Codes and Standards

The following industry design codes are applicable to the design of preliminary options explored in this FEED study.

- Canadian Standards Association (CSA) Z662-07, ‘Oil and Gas Pipeline Systems’;
- CSAZ245.11, ‘Steel Fittings’;
- CSAZ245.12, ‘Steel Flanges’;
- CSAZ245.15, ‘Steel Valves’.

4.3 Design Specifications

Materials shall be specified according to parameters outlined in Figure 4.

Figure 4: Line Pipe Specifications

Specification	Muskwa River Crossing
Start Location	KP17.3
End Location	KP 17.6
Design Service	Sweet Dry Natural Gas
Outside Diameter	168.3 mm
Wall Thickness	7.11 mm
Pipeline Length	300 to 460 m
Material Code	CSA Z245.1
Material Grade	Gr. 290
Material Category	Cat II
MOP	7,960 kPa
Class Location	3
Design maximum stress	Design to 56% SMYS (Class 3) Allowable 72% SMYS (Class 1)
Seam	ERW
Design Temperature	-18 to +50 °C
Coatings	CSA 245.20/21 Shaw Bredero DPS
Joint Coating	Brush Grade Epoxy / HDD Heat Shrink Sleeve

4.4 Cost Estimate

Cost estimates for all proposed options were developed to AACE Recommended Practice No. 18R-97 and are considered Class 4 Estimates with the following tolerances: low -30%, high +50%.

Estimates are built based on resource loading; meaning the number of man hours and equipment is estimated based on construction task using 2009 Fort St. John pipeline contractor rates. Construction tasks are defined based on the preliminary designs developed and included in the Appendices. Non-binding quotes were received for all major materials or equipment.

A contingency of 15% has been added to account for miscellaneous services, materials, shipping and labour. No cost escalation factors were employed to account for accruals to be incurred in the future.

4.5 Schedule

Each proposed design option has construction and regulatory schedule limitations based on whether or not instream work is required. These limitations are defined within each Section of the report for each option. Figure 5 defines the general instream limitations for construction activities based on species of sport fish that may be present in the Muskwa River. Based on Table 5, the Muskwa River has an instream work window of July 15th to August 15th. A site-specific fish and fish habitat assessment may alter this window as other fish species may be discovered.

Individual (high level) construction schedules are included with each cost estimate package attached in the Appendices.

One species of significant concern is the arctic grayling as they are extremely silt-intolerant which thereby could severely limit any instream activities.

Figure 5: Fish Timing Windows For Selected Species – BC Peace Region (BC OGC 2005)

	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Arctic grayling				1	-	-	15					
Bull trout	-	-	-	-	-	15		15	-	-	-	-
Burbot	15	-	-	-	-	15						
Kokanee	-	-	-	-	31				1	-	-	-
Lake trout	-	-	-	-	-	15			1	-	-	-
Lake whitefish	-	-	-	-	-	15			1	-	-	-
Northern pike					1	30						
Mountain whitefish	-	-	-	-	-	15			1	-	-	-
Rainbow trout				1	-	-	15					
Walleye					1	30						
Yellow perch				15	-	-	15					

Low Risk	Timing restrictions would not generally apply. It is recommended that operations are planned for within these timeframes, where ground conditions permit.
Cautionary	Operations may proceed subject to Oil and Gas Commission review. It is recommended that operators avoid intensive activities or overlapping operations during these timeframes. Additional mitigation measures may be required.
Critical	Some operations may not be appropriate during these windows of restricted activity. Heli-supported activities are to be avoided during the periods identified. Exploration and transmission development would generally be permitted. In the event that working within a *critical* window is unavoidable, operations must be accompanied by a rationale, mitigation and/or monitoring plans.

4.6 Regulatory Approvals

In BC, the Provincial Water Act provides standards to reduce disturbance to aquatic habitat and fauna that may result from instream activity associated with petroleum road, or other petroleum or pipeline-related operations in British Columbia (British Columbia Ministry of Water, Land and Air Protection, MWLAP 2004a). In addition, timing windows set by the British Columbia Oil and Gas Commission (BC OGC 2005) describe acceptable timing for oil and gas project works in fish-bearing streams and are used as a tool to reduce adverse affects of construction-related disturbances to fish species during sensitive life-history stages (Figure 5). Best Management Practices (BMP) provided by the BC OGC (2004) outline the most favourable construction methods. Although somewhat flexible, any requested variation to the timing windows or BMPs may require a site-specific review to determine the level of sensitivity related to any particular work instream. Provincial and federal agencies (e.g., BC Ministry of Environment) may participate in such revisions or refinements.

The Federal government, through Transport Canada and the Navigable Waters Protection Act (NWPA), provides for uninterrupted navigation of Canada's waterways. The Federal government, through Fisheries and Oceans Canada (DFO), also has jurisdiction through the Fisheries Act over watercourses that may be affected temporarily or permanently, by crossing construction. The Fisheries Act prohibits the destruction of fish; harmful alteration, disruption, or destruction of fish habitat (HADD); and deposition of deleterious substances into water frequented by fish, or into places that may result in the deposition of deleterious substances into other water frequented by fish (sections 32, 35, and 36 of the Act, respectively). The Fisheries Act is a wide body of legislation that can, in principle, account for landscape level disturbance resulting from cumulative stressors distributed across the watershed. That is, the protection of fishes and their habitat (e.g., stream morphology and hydrology) necessitates an understanding of processes occurring across a watershed. Applications to DFO are dependent upon whether or not instream work is required or whether trenchless crossing technologies shall be employed. DFO also publishes a Crossing Selection Flowchart as a guide used for streamlining the approval of projects. The flowchart is included in Appendix A. If the flowchart is employed for the Muskwa River, only a trenchless crossing is deemed acceptable, either by HDD or an aerial crossing. This flowchart is a guideline and other methods may be approved by DFO upon application given in-situ conditions.

The pipeline is under the jurisdiction of the Oil & Gas Commission of British Columbia. Application will have to be made to the Commission for a Routine process under the existing asset project certificate.

4.7 Other Consultation and Regulatory Approvals

Any work in and around the Muskwa River will require consultation with the following stakeholders:

- Canada Public Works and Government Services:
  - Consultation to confirm no impact to the bridge structure by a trenchless drill path adjacent; alternatively, approvals for hanging a pipeline off the bridge and installation of the pipeline within their highway right-of-way (depending on construction option to be pursued). Preliminary discussions were commenced with the bridge authority on conditions for approval;
  - Application and approval for two temporary access road approaches off of Alaska Hwy #97 to access the job site.
- BC Ministry of Forest and Range:
  - Permission through BC Front Counter to use BC crown land as temporary workspace during construction;
  - A license to Cut for the clearing of temporary workspace; wood volumes will be very small and permission may be granted to burn all wood as scrub or possible ship one or two loads to nearest accepting mill;
  - Consultation for any other restrictions due to wildlife or fauna.
- BC Oil and Gas Commission
  - Application under the Routine process for a pipeline installation; under the Terasen Gas Fort Nelson certificate.
- Canada Department of Fisheries and Ocean
  - Consultation and application for a letter of authorization or letter of notification to cross a fish-bearing watercourse.
- Canada, Transport Canada - Navigable Waters Protection Program
  - Consultation and application for possible interruption of a navigable waterway (depending on construction option to be pursued).

- River Users
  - Possible consultation of users of the boat launch at the project location.
- Fort Nelson First Nations
  - The Fort Nelson First Nations must be engaged in consultation for those alternatives which may impact their lands.

It is unknown at this time if there are any sites of archaeological importance at or near the project site.

5. Option 1 Scope – HDD Crossing

Trenchless technologies include both Horizontal Directional Drills (HDD) and Horizontal Auger Bores and ramming (augers). Trenchless means to cross a watercourse without disturbing the instream portion of the crossing or the banks of the crossing. Trenchless technologies, specifically augers, may have some minor riparian impacts as they are limited by the subsurface geology and in-situ topography (geometry) of the watercourse. An HDD uses a slant drill to traverse under the watercourse and where practical also the stream approach slopes. Option No. 1 proposes to cross the Muskwa River by Horizontal Directional Drill (HDD).

HDD is selected as a crossing methodology for any high fish and fish habitat crossings where suitable subsurface geology exists or where watercourses are likely to be under flowing conditions during construction.

HDD is selected as it allows for:

- No sediment release;
- No disturbance of streambed or banks;
- Maintains streamflow;
- Maintains fish passage;
- Maintains vegetative buffer on both sides of the watercourse;
- Not likely to result in HADD;
- Minimizes clean-up of bed and banks;
- Allows for a large construction window;
- Reduces reclamation activities; and
- Reduces long-term maintenance requirements.

5.1 Scope of Work

An HDD of the Muskwa River would be approximately 460 metres in length based on the preliminary 'peak to peak' design layout shown in Appendix B. For a 460 m drill of 168 mm O.D. pipe, a minimum of a 140,000 ft-lbs rig would be required for the crossing. A second 'low to high' drill alignment may also be feasible. This second alignment would be considerably shorter at 270 metres in length but would result in greater disturbance, as the entry pad would be located on the gravel bar within the watercourse.

Sub-surface conditions at the crossing location are unknown at this time, therefore true feasibility cannot be assessed but subsurface borehole information is available from Ministry of Highways from the 1973 bridge installation at the approximate location of the pipeline crossing of the watercourse. This base borehole data is superimposed on the crossing drawings in Appendix B and shows that along the proposed drill path silt-sand will be encountered at entry, which would tends to indicate that wash-over casing would not be required. Under the channel of the river, the drill path will most likely encounter 'sand-gravel' based on the limited geotechnical information available. This layer may contain cobbles and boulders that would provide considerable risk to the drill but based on current information, the drill is still deemed feasible. More suitable soils may be found at greater depths but information is not yet known at this time to conclude such.

5.2 Land Requirements

A new Right of Way may be required to accommodate the new pipeline. The following temporary workspace is required in order to install a HDD in addition to required pipeline right-of-way.

- A 60m x 50m entry pad located on the south bank of the river on BC Crown lands for a 'peak to peak' drill or in river for a 'low to high' drill, and a 100m temporary access road off Hwy #97 to access the worksite;
- A 40m x 30m exit pad located on the north bank of the river on BC Crown lands and a 100m temporary access road off Hwy #97 to access the worksite;
- A new 12m x 460m right-of-way to accommodate the new drill string;
- Additional strip of temporary workspace, 5m in width x 500m long, may be required to string out the drill string along the TG right-of-way.

All lands are BC Crown land and permissions must be sought from those Ministries having jurisdiction.

5.3 Design Basis

The preliminary HDD design has been laid out according to the following design basis:

- Limitation of 56% hoop stress;
- Limitation of 40% shear stress;
- Limit of 14 to 18 degree entry / exit angles;
- Limit of a 450m radius of curvature.

5.4 Schedule

Upon project initiation, it will take approximately 7 months to design the crossing, procure materials and secure necessary permits, with all activities run concurrently. Total project duration is approximately 10 months. If the project commenced in March of 2010, a drill could be installed by the end of September 2010.

A 460m HDD of the watercourse will likely take approximately 28 days to mobilize, drill and pull back the line pipe. Site preparation, stringing and welding of the drill string and site cleanup will add another 17 days of construction time. The total construction of a HDD crossing of the Muskwa River is approximately 43 workdays. Similar timelines apply to a 'low to high' drill.

The construction schedule is not limited by fish windows and could conceivably be completed in either the fall or winter construction periods.

5.5 Construction Plan

Preliminary and high-level construction plan would be as follows:

- Obtain geotechnical boreholes along the proposed drill path to confirm feasibility;
- Once construction contract and regulatory approvals are in place, general contractor will mobilize to site;
- Contractor is to clear access into the site and project work pads; hauling all merchantable wood to the nearest accepting mill (minimal amounts estimated); all scrub will most likely be able to be burned on-site;

- Contractor is to grade and prepare the drilling work pads and drill string layout areas. Contractor will string, weld and coat owner supplied line pipe to form the drill string;
- HDD (sub)-contractor is to mobilize to site;
- HDD (sub)-contractor will spud the drill, drill a pilot hole (9 7/8" diameter), possibly swab the hole with the pilot string and pull-back the drill string. Back-reaming is most likely not required but is conditional upon the results of a geotechnical investigation;
- HDD (sub)-contractor will demobilize from site once pull-back is complete;
- Contractor will add several joints of pipe to each end of the installed drill string to facility hot tie-ins;
- Terasen Gas tie-in crew will mobilize and using stopple fittings will tie-in and gasify the drill string.
- Contractor will clean-up the work site and de-mobilize.

5.6 Environmental Requirements

A HDD of the Muskwa River offers the benefit of not disrupting the instream or banks of the watercourse and limits damage to the watercourse riparian. Installation would employ all best management and construction practices including off-site trucking of drilling mud for disposal.

5.7 Cost Estimate

Detailed cost estimate summary sheet is included in Appendix B and the total installed estimate for a 'peak to peak' crossing of the Muskwa River by HDD is:

Lower Bound (-30%)	Mean	Upper Bound (+50%)
$ 1,143,900	$ 1,643,200	$ 2,451,300

The total installed estimate for a 'low to high' crossing of the Muskwa River by HDD is:

Lower Bound (-30%)	Mean	Upper Bound (+50%)
$ 1,045,700	$ 1,493,900	$ 2,240,800

These options are compared against other construction options in Section 10.

Major risks of the HDD include:

- Subsurface conditions that reduce or eliminate the probability of completing a successful drill;
- A 'frac-out' midstream that requires significant clean-up effort. It is important to note that a drill may be completed while 'frac'ing' into a fish-bearing stream provided mitigation actions are implemented.

5.8 Feasibility and Risk

The success of a HDD is conditional upon the geotechnical subsurface conditions at the crossing location. In-situ geotechnical boreholes must be obtained to definitively determine the likelihood of success of a drill and to also determine 'no drill zones' to set the drill depth and path.

MOT boreholes are available from the 1976 bridge construction but classification of the soils from these borehole logs was not available and the boreholes are relatively shallow (up to 50 feet deep); therefore their usefulness is suspect. The MOT boreholes have been super-imposed on the drawing in Appendix B and show the immediate river sub-surface to consist of gravels, cobbles, and boulders, which leads one to conclude a HDD is not likely to succeed within this zone. These boreholes do not preclude that an acceptable drill path may exist at deeper depths. If the gravels, cobbles and boulders do indeed extend down to a significant depth, substantial monies will be spent on wash-over casing and may render the drill unfeasible.

Paramount Resourced Ltd of Calgary, Alberta also obtained geotechnical boreholes of the Muskwa River upstream by several kilometers of the Terasen Gas crossing. Although the Paramount crossing was cancelled and not completed due to poor gas field results, the crossing was deemed feasible from a geotechnical standpoint.

It is recommended that geotechnical boreholes be obtained at the Terasen Gas crossing location to determine HDD feasibility. The borehole may be obtained by a truck-mounted rig which is highly economic. An adequate number of boreholes are required to determine the subsurface conditions for the full crossing length. The boreholes will also be required to support justification for any in-stream work (Options 2 and 3).

A low to high drill path is presently deemed more likely to succeed simply because it is shorter and allows for more desirable drill string pressures.

6. Option 2 Scope – Open Cut Crossing

To 'Open Cut with Isolation' a watercourse means to block the upstream flow of stream and either divert water through a flume pipe laid in the streambed perpendicular to the pipeline (i.e. an Isolation by Flume), or alternatively dam flow upstream and pump water around via hoses (i.e. an Isolation by Dam and Pump). In both cases the downstream of the crossing is dammed to prevent backflow. The pipeline is installed by trenching through with a mechanical excavator from bank to bank. The excavator typically operates outside of the instream portion of the watercourse but may cross through the stream to access the opposite bank. Pumps and flumes are sized to adequately handle stream flows. Flume capacity may also be augmented by a pump bypass. In cases of high flow where super-flume capacities are exceeded, a flowing river may also be crossed *without* isolation if it is infeasible to install isolation, alternatively the channel may also be dammed and redirected. This is the case for the Muskwa River as isolation is deemed not feasible due to flow rates.

'Open Cut *without* Isolation' is typically selected as a crossing methodology for any low habitat watercourses that are likely not to be under flowing conditions during construction or crossings that are not feasible by trenchless technologies based on a subsurface geotechnical assessment.

Open Cut *without* Isolation is selected as it allows for:

- Maintains streamflow;
- Maintains fish passage;
- Allows for flushing of substrates;
- Compatible to a variety of subsurface geology and surficial soils.

6.1 Scope of Work

An open cut with or without isolation of the Muskwa River would be subject to DFO approval and would likely only occur in the open activity window of July 15th to August 15th; but a gravel removal operation upstream seems to indicate that a site fisheries assessment may yield a much more relaxed construction window. The watercourse has a mean annual flow of 215 m3/s, which is a high volume river and greatly surpasses the capacity of 'super-flumes', therefore to attempt an open cut within the work window would require a open cut *without* isolation.

Based on all hydrology data available, an open cut without isolation would require extra precautions in terms of depth of cover and rip rap to provide long-term integrity due to the highly volatile and meandering channel. Construction would be with either excavators operating directly in-stream or on barges operating on the river. Pipe would be pre-fabricated and dragged into place with tie-ins occurring on the shoreline. A dragline may also be a viable option.

The winter mean flow is approximately 20 m3/s, which also surpasses the capacity of most super-flumes, and therefore isolation is also not a viable option in the winter. The Muskwa River is not known to freeze to bottom and flow will be encountered once ice cover is removed.

Typically, one would expect open cut costs to be significantly lower than horizontal drilling costs but due to the dimensions of the watercourse and volume of flow, this rule of thumb likely does not apply.

6.2 Land Requirements

The following temporary workspace is required in order to install an open cut in addition to existing pipeline right-of-way.

- A 50m wide workspace would be required for the length of the crossing, including each bank extended upslope past the provincial riparian boundaries. A significant amount of HADD will be incurred from this workspace;
- Two 100m temporary access roads off Hwy #97 to access both sides of the worksite;
- Workspace on both banks and upland areas is required for set-up. Area would be 100m long by 20 m wide on both sides of the crossing.

All lands are BC Crown land and permissions must be sought from those Ministries having jurisdiction.

6.3 Design Basis

The preliminary design has been laid out according to the following design basis:

- Limit of 5D induction bends;
- Limit of 40D field cold bends;
- Depth of cover to a 1:200 year flood event;

- Limit of negative 10% buoyancy in-stream.

6.4 Schedule

Upon project initiation, it will take approximately 14 months to design the crossing, procure materials and secure necessary permits, with timing of activities severely restricted due to the necessity of completing a Fish and Fish Habitat Assessment in the spring, and construction limited to an open fisheries window in the summer. It is too late in 2010 to be able to construct in the summer of 2010. Total project duration is approximately 20 months. If the project commenced in March of 2010, a crossing could be installed by the end of September 2011.

An open cut crossing of the watercourse will likely take approximately 20 days for site preparation, stringing, and welding of the pipe. In-stream construction would last for approximately 14 days. The total construction of an open cut crossing is approximately 35 workdays.

Construction timing during the year is limited to an open fisheries window of July 15th to August 15th.

6.5 Construction Plan

Preliminary and high-level construction plan would be as follows:

- Obtain DFO approvals and pre-negotiate HADD requirements;
- DFO will likely make Terasen Gas pre-build the majority of HADD compensation. The riparian and instream disturbance is 15,350 m2 resulting in 30,700 m2 of compensation due (using a 2:1 ratio);
- Once construction contract and regulatory approvals are in place, general contractor will mobilize to site;
- Contractor is to clear access into the site and project work pads; hauling all merchantable wood to the nearest accepting mill;
- Contractor is to grade right-of-way and riparian;
- Contractor will string, weld and coat owner supplied line pipe to form the drag-in section;

- Contractor will mobilize a small barge for excavation in-stream. This may not be necessary but is subject to regulatory requirements although it is believed it would greatly expedite the work. Drag line is the alternative but elevates risk of digging next to the hotline;

- Contractor will excavate the trench line. Due to erosion of the flowing channel, width of the excavation will likely to 30 to 40 metres wide. New fill may have to be imported based on river hydrology reporting and flood stage design requirements;

    - Alternatively, DFO may request that the channel be diverted around and through the gravel embankment by use of a coffer dam. This would require the trenching and placement of significant amounts of the gravel river substrate to dam and divert the existing channel; it is believed this would result in costs towards the upper bound of the Open Cut Estimate.

- Contractor will drag in the pipe and prepare tie-ins on land within the riparian zone;

- Terasen Gas tie-in crew will mobilize and using stopple fittings will tie-in and gasify the drill string.

- Contractor will clean-up the work site and de-mobilize.

6.6 Environmental Requirements

An open cut will result in a massive disturbance of both the in-stream and riparian areas of the watercourse. Preliminary estimate of the area of disturbance is 15,350m2. Assuming a 2:1 HADD ratio, ‘like for like’ restoration projects would have to be located resulting in remediation of 30,700m2 of fish habitat.

It is estimated that to locate HADD compensation areas, develop plans and remediate would cost $10 / m2.

6.7 Cost Estimate

Detailed cost estimate summary sheet is included in Appendix C and the total installed estimate for the crossing of the Muskwa River by open cut is:

Lower Bound (-30%)	Mean	Upper Bound (+50%)
$ 1,287,200	$ 1,838,900	$ 2,758,300

This option is compared against other construction options in Section 10.

Major risks of the Open Cut include:

- Eroding of the instream trench line requiring significant volumes of material to be removed and replaced with aggregate;
- Cost of imported materials (aggregate and rip-rap);
- Cost of HADD restoration and monies required to find 'like for like' projects;
- Working instream and resulting environmental impact;
- Unknown requirements imposed by DFO.

6.8 Feasibility and Risk

From a construction standpoint, the open cut of the Muskwa River is feasible but regulatory permitting to be allowed to conduct in-stream works may be very difficult to impossible. A number of studies and justifications will be required to obtain a letter of authorization from DFO authorizing in-stream work. These studies include:

- A Fish and Fish Habitat Assessment;
- Hydrological studies of the channel;
- Geotechnical Boreholes demonstrating that a HDD has a very high probability of failure.

DFO may also insist that a HDD must be completed (and fail) before any in-stream work may be approved.

In-stream work also results in HADD, which may have to be bonded guaranteeing up to ten years of maintenance and functionability of the HADD. This is an unknown cost and could result in hundreds of thousands of dollars of unplanned operating expenditures.

It is recommended that the Open Cut in-stream option be used as a method of last resort.

7. Option 3 Scope – In Stream Remediation

In stream remediation would involve excavating and completing a live line lowering of the existing line to re-establish depth of cover requirements.

7.1 Scope of Work

As explained in Section 6.1, all in stream work would most likely have to occur without isolation and within existing fisheries open windows (July 15th to August 15th); otherwise massive HADD will be incurred (possibly surpassing the 2:1 ratio for compensation). To complete a live lowering, the existing hot line will have to be supported every 9 metres by supports or machines (cranes, side-booms). Excavators on barges or a dragline would be employed to open a massive eroding trench across the watercourse. Due to the high volume flow of the river, it will be extremely difficult to maintain trench integrity / stability in the silty-sandy base of the river and the resulting excavation will most likely be H12m:V4m for a total width of up to 30m to 40m wide.

'Live Lowering by Open Cut without Isolation' is selected as a crossing methodology as in certain cases it is significantly less expensive than replacement of a line.

'Live Lowering by Open Cut without Isolation' is selected as it allows for:

- Maintains streamflow;
- Maintains fish passage;
- Allows for flushing of substrates;
- Compatible to a variety of subsurface geology and surficial soils;
- Minimizes material and fabrication costs.

7.2 Land Requirements

The following temporary workspace is required in order to complete a live lowering of the existing pipeline:

- A 50m wide workspace would be required for the length of the crossing, including each bank extended upslope past the provincial riparian boundaries. A significant amount of HADD will be incurred from this workspace;

- Two 100m temporary access roads off Hwy #97 to access both sides of the worksite;

- Workspace on both banks and upland areas is required for set-up. Area would be 100m long by 20 m wide on both sides of the crossing.

All lands are BC Crown land and permissions must be sought from those Ministries having jurisdiction.

7.3 Design Basis

The preliminary design has been laid out according to the following design basis:

- Limitation of longitudinal bending stresses according to API 1117;

- Depth of cover to a 1:200 year flood event;

- Limit of negative 10% buoyancy in-stream.

7.4 Schedule

Upon project initiation, it will take approximately 14 months to design the crossing, procure materials and secure necessary permits, with timing of activities severely restricted by the necessity of completing a Fish and Fish Habitat Assessment in the spring, and construction limited to an open fisheries window in the summer. It is too late in 2010 to be able to construct in the summer of 2010. Total project duration is approximately 20 months. If the project commenced in March of 2010, the lowering could be installed by the end of September 2011.

A live lowering in the watercourse will likely take approximately 7 days for site preparation. In-stream construction would last for approximately 25 days. The total construction of a live lowering is approximately 40 workdays.

Construction timing during the year is limited to an open fisheries window of July 15th to August 15th.

7.5 Construction Plan

Preliminary and high-level construction plan would be as follows:

- Obtain DFO approvals and pre-negotiate HADD requirements;
- Once construction contract and regulatory approvals are in place, general contractor will mobilize to site;
- Contractor is to clear access into the site and project work site; hauling all merchantable wood to the nearest accepting mill;
- Contractor is to grade right-of-way and riparian;
- Contractor will mobilize a small barge for excavation in-stream. This may not be necessary but is subject to regulatory requirements. Drag line is the alternative but elevates risk of digging next to the hotline;
- Contractor will excavate an offset trench line to the hotline. This will slowly expose the hotline as it is allowed to 'washout' until exposed. Due to erosion of the flowing channel, width of the excavation will likely to 30 to 40 metres wide;
- As the pipeline is exposed, it will have to be supported every 9 metres by use of cranes, sidebooms, air bags or earth fill supports. This will be extremely costly and possibly require significant engineering design to both ensure support stability and minimize construction costs;
- A controlled lowering of the pipeline will occur by use of crane or side boom on barge in conjunction with an excavator to remove support structures as the pipeline is lifted and lowered;
- New fill may have to be imported and placed based on river hydrology reporting and flood stage design requirements;
- Contractor will clean-up the work site and de-mobilize.

7.6 Environmental Requirements

An open cut will result in a massive disturbance of both the in-stream and riparian areas of the watercourse. Preliminary estimate of the area of disturbance is 15,350m2. Assuming a 2:1 HADD ratio, 'like for like' restoration projects would have to be located resulting in remediation of 30,700m2 of fish habitat.

It is estimated that to locate HADD compensation areas, develop plans and remediate would cost $10 / m2.

7.7 Cost Estimate

Detailed cost estimate summary sheet is included in Appendix D and the total installed estimate for the crossing of the Muskwa River by live lowering is:

Lower Bound (-30%)	Mean	Upper Bound (+50%)
$ 1,369,300	$ 1,956,200	$ 2,934,200

This option is compared against other construction options in Section 10.

Major risks of the live lowering include:

- Eroding of the instream trench line requiring significant volumes of material to be removed and replaced with aggregate.
- Exposing and excavating the hot line in order to support and lower.
- Completion of the lowering operation and controlling bending stresses.
- Condition of the existing line and the possibility of discovering major corrosion or mechanical defects (unknown condition of the existing line).
- Required depth of lowering may exceed allowable stress limitations if major corrosion or mechanical defects are discovered.
- Cost of imported materials (aggregate and rip-rap).
- Cost of HADD restoration and monies required to find ‘like for like’ projects.
- Working instream and resulting environmental impact.

7.8 Feasibility and Risk

From a construction standpoint the live line lowering of the Muskwa River is feasible but regulatory permitting to be allowed to conduct in-stream works may be very difficult to impossible. A number of studies and justifications will be required to obtain a letter of authorization from DFO authorizing in-stream work. These studies include:

- A Fish and Fish Habitat Assessment;
- Hydrological studies of the channel;

- Geotechnical Boreholes demonstrating that a HDD has a very high probability of failure.

DFO will have to be convinced that in-stream remediation is the best option and the resulting environmental impact offsets not having to abandon this line to replace it.

In-stream work also results in HADD, which may have to be bonded guaranteeing up to ten years of maintenance and functionability of the HADD. This is an unknown cost and could result in hundreds of thousands of dollars of unplanned operating expenditures.

It is recommended that the live line lowering in-stream option be used as a method of last resort.

8. Option 4 Scope – Gate Station & IP Bridge Crossing

8.1 Scope of Work

The existing Fort Nelson Gate Station is located at kp 19.0 of the Fort Nelson lateral just outside the town of Fort Nelson, north of the Muskwa River. The possibility exists of replacing and relocating the Gate Station to the south bank of the river and installing an intermediate pipeline aerial crossing of the Alaska Hwy #97 bridge of the Muskwa River. Project would consist of:

- Installing a new TP/IP Gate Station upstream of the bridge;
- Installing a new IP bridge crossing on the Alaska Hwy #97 bridge of the Muskwa River;
- Lower the operating pressure of the pipeline from the new TP/IP Gate Station to the existing Gate Station to 1896 kPa (asset is presently operating at transmission pressure);
- Modify the existing Fort Nelson Gate Station to operate as an IP/DP regulating station with the existing TP/IP portion being decommissioned.

8.2 Land Requirements

The following temporary workspace is required in order to install a bridge crossing and new gate station in addition to existing pipeline right-of-way.

- Approvals with Canada Public Works to install approximately 600 metres of new pipeline within their highway right-of-way to access the bridge crossing and relocate back to the existing Terasen Gas pipeline right-of-way.
- Approvals with Canada Public Works – Bridge Authority will have to be granted to hang a 210 metres IP168mm pipeline from the bridge deck.
- A 100m x 50m site will be required on the south bank of the river for the new TP/IP regulating station.

All lands are BC Crown land and permissions must be sought from those Ministries having jurisdiction.

8.3 Design Basis

The preliminary pipeline design has specified to the following design basis:

- Limitation of 50% design stress for a class 3 location.
- Limitation of a Maximum Operating Pressure of 2068 kPa (300 psig).

8.4 Schedule

Upon project initiation, it will take approximately 7 months to design the crossing, procure materials and secure necessary permits, with all activities run concurrently. Total project duration is approximately 11 months. If the project commenced in March of 2010, a bridge crossing and regulating station could be installed by the end of November 2010.

An 810m IP168mm pipeline including a 210m bridge installation and regulating gate station construction will likely take approximately 50 days to complete.

No timing restrictions are known.

8.5 Construction Plan

Preliminary and high-level construction plan would be as follows:

- Contractor is to mobilize to site;
- Contractor is to clear all right-of-way and work sites of all vegetation; hauling all merchantable wood to the nearest accepting mill;
- Contractor is to grade and grub right-of-way and station sites;
- Contractor is to install the new TP/IP regulating gate station;
- Contractor is to install the new bridge crossing:
    - Contractor to erect scaffolding and pickers;
    - Contractor to hang bridge supports from the deck;
    - Contractor to string, weld and coat pipe section to be pulled into place through all bridge supports;
    - Contractor to nightcap bridge crossing pipe and expansion loops in preparation of pipeline tie-ins.

- Contractor will install the new IP168mm pipeline:
    - Contractor to commence at bridge crossing; excavating, stringing, welding, coating and backfilling owner supplied line pipe;
    - Contractor will tie-in pipeline to both the new station and bridge crossing;
    - Contractor to cap new pipeline in preparation for Terasen Gas hot tie-ins.
- Terasen Gas tie-in crew will mobilize and using stopple fittings will tie-in and gasify the new pipeline and gate station;
- Terasen Gas to decommission the TP/IP portion of Fort Nelson Gate Station;
- Contractor will clean-up the work site and de-mobilize.

8.6 Environmental Requirements

Construction will be completed to Terasen Gas and industry best management practices, including a river watch to ensure no materials are dropped or discharged in to the Muskwa River during bridge crossing installation.

8.7 Cost Estimate

Detailed cost estimate summary sheet is included in Appendix E and the total installed estimate for the crossing of the Muskwa River by bridge crossing and related facilities is:

Lower Bound (-30%)	Mean	Upper Bound (+50%)
$ 1,550,400	$ 2,214,900	$ 3,322,400

This option is compared against other construction options in Section 10.

Major risks of the Bridge Crossing include:

- Approvals with the Federal Government for installing a bridge crossing;
- Safety during construction for erection of scaffolding and the use of pickers for installing the bridge hangers;
- Asset life of the existing bridge and need for replacement in the near future;

- Working over a watercourse of high fisheries value and implementation of construction practices to eliminate the possibility of deleterious material being discharged into the river.

8.8 Feasibility and Risk

From a construction standpoint the installation of the bridge crossing and station relocation is highly feasible and offers the lowest overall risk of all options evaluated.

Preliminary discussions have occurred with Virendra (Vinni) K. Sahni, the senior bridge engineer at the Department of Public Works of the Federal Government, and he is strongly opposed to hanging a low pressure gas line from any bridge along the Alaska Highway.

Discussions were also commenced with Paddy Whidden, Alaska Highways Manager with the Department of Public Works. He has indicated a preliminary study was completed by a hydrologist identifying a problem at this location in regards to bank stability that must be remediated (preliminary discussions talked of a possible channel diversion). No plans have been finalized and a detailed review is to be initiated. Presently the bridge embankment/abutment is protected by gabion baskets but there is concern about water migrating behind them. It is envisioned that repair options may include:

- Flattening out the erosion of the banks and placing rip-rap, or
- Installing a spur / training dike to divert the channel.

To obtain permissions from the Department of Public Work to hang a low pressure gas line, more formal discussions will have to occur with possibly approaching senior bureaucrats about the benefits of a bridge crossing.

9. Option 5 – 'Do Nothing' Option

At present the pipeline is exposed for 12 metres at the thalweg but still remains fully supported i.e. an unsupported pipe span has not formed by erosion. Under this condition, a number of mechanisms could result in an immediate impact on pipe integrity or potentially create a future integrity impact. Threats to the pipe integrity include:

- Line strike by a large boulder or cobble during a high flow event resulting in a large dent with a gouge or potentially a line fracture;
- Line strike by a third party operating on the river in either a commercial or recreational fashion; resulting in a large dent with a gouge or potentially a line fracture;
- Excessive pipe deflection caused by further erosion of the thalweg resulting in an unsupportable exposed pipe length.

The thalweg may further erode creating an unsupported pipe span. Based on the pipe specification, weight of water over the pipe and force of flowing water striking the pipe, pipe buckling may result once deflections approach 15 to 20%.

Under favorable flow conditions, the pipe may remain intact for many years under its present condition but the risk to the pipe and risk to the surety of natural gas supply to the town of Fort Nelson is high under the present condition. It is recommended that the 'do nothing' option not be pursued and pipe remediation be employed as soon as practical.

10. Comparison of Options and Evaluation

Comparison of all four options can be found in Appendix F. Based on the comparison, the following is recommended:

- Recommended Option: HDD of the Muswka River as the preferred course of action. Class 4 cost is $ 1,493,900.
- Contingency Option No. 1: Due to forseen difficulties with DFO permitting, it is recommended that the first contingency be to pursue Option 4 – Station Relocation and Bridge Crossing. Class 4 cost is $2,241,900.

- If geotechnical investigations determine that a drill is not feasible and DPW permits cannot be obtained, pursue Option 2 – Open Cut of the Muskwa River. Class 4 cost is $ 1,838,900. This option will be listed as the contingency to the DFO within the application for a letter of authorization / notification to cross the watercourse.

11. Summary

It is the recommendation of this document to proceed with Option 1, installation of a new HDD crossing of the Muskwa River.

Sincerely,

"David Bainbridge"

David Bainbridge, P.Eng

PROFESSIONAL PROVINCE OF D. G. BAINBRIDGE # 30022 BRITISH COLUMBIA ENGINEER

Appendix A

Muskwa River Hydrology and Existing Pipeline Crossing

Appendix B

Option 1 – Front End Engineering and Design

Appendix C

Option 2 – Front End Engineering and Design

Appendix D

Option 3 – Front End Engineering and Design

Appendix E

Option 4 – Front End Engineering and Design

Appendix F

Option Comparison and Evaluation

Appendix B

32004.0901 – MUSKWA RIVER CROSSING CLASS 4 PIPELINE ESTIMATING PACKAGE

32004.0901 – Muskwa River Crossing,
Fort Nelson, BC

Class 4 Pipeline Estimating Package
(Rip Rap Remediation Options)

Prepared for Terasen Gas Inc.
By David Bainbridge, P.Eng

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Table of Contents

Appendices

1. Introduction

1.1 Project Background and Location

The 168mm O.D. Fort Nelson transmission lateral crosses the Muskwa River at kilometre post 17+300 and is presently at risk due to severe channel scour as the pipeline is exposed at the thalweg of the watercourse. Immediate action is required, as the risk to the pipeline has been classified as High according to the Terasen Geotechnical Hazards Database.

This document is a supplement to the Muskwa River Crossing Front-End Engineering Design document (03Mar10) as it explores capital expenditures of two alternative instream rip rap remediation options. The two methods evaluated are:

1. Rip Rap of the channel with D50:300mm fractured rock.

2. Rip Rap blanket of the crossing implementing “cabled-concrete” mats.

Design, implementation and construction of both options are effectively the same with the only fundamental difference being how the rip rap is installed within the watercourse.

1.2 Estimate Scope

This document outlines and summarizes costs to remediate the exposed Muskwa River crossing. The estimate has been developed to AACE Recommend Practice No. 18R-97 and is considered a Class 4 Estimate with the following tolerances: low -30%, high +50%.

A contingency of 15% has been added to account for miscellaneous services, materials, shipping and labour. No cost escalation factors were employed to account for accruals to be incurred in the future (i.e. inflationary measures).

2. Pipeline Design Parameters

2.1 Stream Characteristics

The Muskwa River is within the McKenzie River basin in northeastern British Columbia and has an assumed BC Riparian Class of S1-B; meaning the active flood plain is a function of the stream channel dimensions (channel width is greater than 100m wide). As an S1 classified watercourse, the watercourse is ranked as having high fish and fish habitat value with a Riparian Management Area of 70 m and a Riparian Management Zone of 20 m.

The Muskwa River has a mean annual flow rate of 215 m3/s according to a Water Survey of Canada polling site upstream of the crossing location.

The crossing location is subject to severe scour due to both contraction scour caused by a reduction in the river width at the gravel bar and localization scour caused by the adjacent bridge abutments.

Contraction scour results from acceleration of flow due to a constriction, such as a bridge or revetments (obstructions) that reduce stream width. This type of scour is generally limited to the length of the contraction and a short distance upstream and downstream of it. Local scour occurs at piers, abutments, riprap revetments, large woody debris or other structures obstructing the flow. These obstructions cause vortexes with accelerated flow that erode the surrounding sediments. General scour is the natural variation in bed levels that occurs due to the complex interaction between hydrology, sediment transport rates and channel morphology. An example of general scour is the natural riffle-pool sequence in lower-gradient rivers, where a deeper pool can develop in the middle of a channel. The Muskwa River is also subject to ice flow scour during winter and spring break-up.

Any instream rip rap solution must correct and resist the existing scour that has exposed the pipeline and protect against future river and ice scour. Based on the initial understanding of the hydrology of the river, it is believed that the application of rip rap, both instream and along the river bank, is a viable solution.

Preliminary hydrological design parameters are listed on the next page.

CROSSING DESIGN SUMMARY, MUSKWA RIVER

HYDROLOGY	
Drainage Area, km^2	--
Design Flood (1:100 year), m^3/s	> 300 m3 / s
BANKFULL CHANNEL GEOMETRY	
Average Slope (est.)	0.0004
Bankfull Stage, m	300 m geodetic
Bankfull Discharge, m^3/s	-- (yearly ave. 215)
Average Bankfill Width, m	200 m
Average Water Surface Width, m	80 m (at survey)
Average Bankfill Depth, m	12.0 m
Average Velocity, m/s	0.75 m / s
DESIGN FLOOD DATA	
Peak Flood Stage, m	302.0 geodetic
Mean Flow Depth, m	14.0
Average Velocity, m/s	--
SCOUR COMPUTATIONS	
Reference Level, m	288 geodetic
Scour Multiplier	1.7
Maximum Scoured Depth, m	--
Design Scour Elevation, m	286 geodetic
Minimum Bed Elevation[1], m	288 geodetic
Depth of Scour, m	2.0
Allowance for Degradation, m	--
DESIGN RECOMMENDATIONS	
Minimum Cover (below surveyed thalweg elevation), m	2.5
Maximum Allowable Top Elevation of Pipeline or Concrete Coating[2], m	285.5 geodetic

1 At time of survey
2 Between sagbends at Stations 0+98 and 2+68

NOTE: All values are preliminary based on developed conceptual design. Hydrological analysis has not been completed.

2.2 Construction Estimating Assumptions

The following assumptions, with regards to project construction, have been made for estimating purposes:

- Traffic Management – One full-time traffic control person shall be employed for the duration of construction to direct and manage heavy equipment and material (aggregate) load in / load out.

- Access – Two temporary access roads will be constructed off the Alaska Highway to access both the north and south bank of the river. Minimal clearing will be required to construct these access routes.

- Site Infrastructure – The pipeline contractor will mobilize a simple site office trailer, which may double as a small tool crib. Site infrastructure and rentals for the duration of construction include:

    - Two portable toilets; one for each bank of the river.

    - Two portable electrical generating sets to power small tools and pumps. All pumps used in water damming and diverting activities are assumed to have 100% capacity backups.

- Site Security – An overnight watchman is assumed to man the operation of all operating water pumps. No provision has been made for overnight site security.

- Delivery of Materials - All materials shall be classified as “Free-On-Board” at each respective vendor or manufacturer’s location or depot. It shall be the contractor’s responsibility, unless otherwise indicated, to identify and contract for the requirements for the transportation of goods to site and their handling to specification.

- Delivery of Cabled Concrete - A flat deck is capable of transporting 150 m2 of cabled concrete and transportation is assumed to be 18 hours at $250 / hr for driver and rig or $4500 per load.

- Delivery of D50 Rip Rap – Limited rip rap is available from a local Fort Nelson pit. Currently no rock is available at this pit. Alternatively rip rap must be transported from Fort St John at 150 / m3. The estimate assumes all rip rap is available locally with a one hour delivery time at $165 / hr.

- Right-of-Way Construction Width – It is assumed the following lay-down areas will be acquired and cleared for construction:

    - Quantity two – 100 m long x 10m wide access temporary access roads.

- Quantity two – 100m x 100m lay down areas centred on the Terasen right-of-way directly adjacent to the riparian boundaries on the south and north river banks.
- A 50m wide construction right-of-way for the length of the crossing from riparian boundary to riparian boundary for a total length of 240 metres.

- Erosion Control – Erosion control measures shall be installed before grading operations consisting of: silt fencing, straw bales and run-off prevention measures.
- Right-of-Way Clearing and Grubbing – The entire length of construction right-of-way will be cleared and grubbed including the removal of all trees, brush, and existing deadfall/ stumps. Based on review of aerial photography, this clearing work is assumed to be minimal and will be completed by excavator. No feller-bunchers are assumed to be required. It is assumed no merchantable timber exists within the construction right-of-way. All debris will be burned, chipped or dumped.
- Right-of-Way Grading – Grading shall be completed for equipment travel and lay down of material. No provision for topsoil conservation has been made as the soil subsurface will not be disturbed.
- Grade Rock – Based on existing knowledge of the soil subsurface from highways bridge pier boreholes, no provision has been allowed for blasting or ripping of grade rock.
- Foreign Utilities – No foreign utilities have been identified. It is assumed safe clearance distances shall be maintained from any overhead powerlines and no special provisions are required.
- Welding – No provision for pipe replacement or repair has been estimated.
- Pipe Coatings – It is assumed that 5% of all exposed pipe surface area will require recoating.
- Pipe Bedding – Exposed pipe at the river thalweg shall be embedded in sand for 300mm above the top of pipe. An additional 300mm of river pit run shall be placed above the pipe for a total depth of cover of 600mm. Rip rap shall be placed above this cover.

- Rip Rap – Both D50:300mm rip rap or alternatively cabled concrete mats shall be placed for the full length of the water crossing from south top of bank to north top of bank (200m). The rip rap shall extend 20m upstream and downstream of the pipe centreline for a full width of 40m at a maximum gradient of 5^{o}. All aggregate shall be placed by excavator or dragline. Cabled concrete mats shall be placed by excavator or crane depending on location. Minimum depth of rip rap shall be 600mm to a maximum of 1000mm.

- Water Control & Pipe Condition Assessment – A two-stage cofferdam is proposed to isolate the pipeline from the flowing portion of the river to investigate the condition of the pipe and recoat. First stage of the cofferdam will isolate 40 meters of pipe against the south gravel bar and the second stage will isolate approximately 40 metres of pipe against the north bank. All other instream pipe (unsubmerged) is not proposed to be excavated and inspected as there is no reason to believe it has sustained damage but it will be inspected by indirect methods and exposed by exception. Pumps will be required to operate 24 hours per day to maintain moderately dry conditions within the cofferdam. It is assumed no major defects, gouge features or plain dents will be discovered that exceed 6% of wall thickness that require repair or pipe replacement. Condition Assessment is discussed in Section 2.3.

- Warning Signs – Signs shall be at the top of each bank indicating a pipeline crossing of the river.

- Test Leads - No provision for test leads has been estimated.

- Hydrostatic Testing – No provision for pipe replacement or repair has been estimated.

- Right-of-Way Clean up - Primary clean-up to be completed as soon as practical following construction with a small summer restoration crew to complete: reseeding, vegetation clean up, and seepage control the following year.

- Harmful Alteration, Disruption, or Destruction of fish habitat (HADD) – total area of disturbance is assumed to be 15,000 m2. Using a 2:1 compensation ratio, which is typical for instream works, total HADD incurred by the project is 30,000 m2. It is assumed that the cost to locate and repair ‘like for like’ habitat will be $10 / m2.

- Construction Inspection – Inspection shall include one lead inspector and one environmental inspector for the full duration of the construction.

2.3 Coating Evaluation

The options explored within the document assume the pipeline asset integrity is in good condition without any significant corrosion defects, gouges or plain dents (i.e. features that exceed allowances prescribed within CSA Z662). During construction, the coating condition and asset shall be evaluated utilizing the following methods:

- Visual inspection of the instream exposed portion of the pipeline.
- ECDA evaluation of the full width of the crossing.

3. Total Installed Costs

3.1 Cost Summary – D50:300mm Rip Rap

A detailed cost estimate summary sheet is included in Appendix A and the total installed estimate for the instream remediation is:

Lower Bound (-30%)	Mean	Upper Bound (+50%)
$ 1,366,085	$ 1,951,550	$ 2,927,325

The unit cost of design-construction is $ 8,131 per meter (240 meter crossing).

Major costs of the option include:

- $300,000 for HADD compensation costs (15% of total cost).
- $502,500 for D50 rip rap material costs (26% of total cost).

Compared to the least cost option of a low to high horizontal directional drill at an estimated cost of $ 1,493,850, revetment remediation of the crossing by D50 rip rap is more expensive by $ 457,700. If rip rap must be trucked from Fort St John as none may be available in Fort Nelson, the total installed cost will rise to $2,906,050 or a surcharge of $ 954,500.

3.2 Cost Summary – Cabled Concrete Mats

A detailed cost estimate summary sheet is included in Appendix B and the total installed estimate for the instream remediation is:

Lower Bound (-30%)	Mean	Upper Bound (+50%)
$ 2,065,630	$ 2,950,900	$ 4,426,350

The unit cost of design-construction is $ 12,295 per meter (240 meter crossing).

Major costs of the option include:

- $300,000 for HADD compensation costs (10% of total cost).

- $1,386,000 for transported cabled concrete mats (47% of total cost).

Compared to the least cost option of a low to high horizontal directional drill at an estimated cost of $ 1,493,850, revetment remediation of the crossing by D50 rip rap is more expensive by $ 1,457,050.

3.3 Included Costs

The following costs are included in the estimates:

- Aggregate materials including cabled concrete mats, D50:300mm fractured rock, sand and pit run gravel.
- Field contractor's labour, equipment, consumables, home office costs and profit.
- Engineering, procurement and construction management costs.
- Construction monitoring and inspection, material quality control inspection and environmental monitoring and inspection.
- Third party costs such as non-destructive examination (NDE), hydrovac, services, surveying, pressure and water trucks, etc.
- All miscellaneous materials of construction and installation.
- Provincial Sales Tax on materials.
- Contingency of 15% to cover miscellaneous items and unforeseen construction impacts.

3.4 Excluded Costs

The following costs are excluded from the estimates:

- Development costs to date.
- Repair or replacement costs in the event major pipe defects are discovered.
- Third party legal, environmental, public relations and land services or permits.
- Construction right-of-way acquisition costs or timber stumpage costs.
- Municipal or third party negotiations.
- Goods and Services Tax on material, labour and services.

4. Estimate Methodology

4.1 Reference Documents

The estimates were developed using the information provided in the following documents:

- 32004.0901 Muskwa River Crossing FEED Study (03Mar10).
- BGC Engineering Inc - Terasen Gas Stage 3 Hydrotechnical Risk Analysis of Selected Crossings in British Columbia, Report 0093-065-05 (31Dec08).

4.2 Survey Drawings

No survey drawings for the pipeline are available.

4.3 Detailed Engineering Drawings

No detailed engineering drawings were completed for the remediation work.

4.4 Unit Price Costs and Quantities

Unit price costs were estimated based on recent experience and consultations with local contractors.

Unit prices quantities were estimated using typical pipeline estimating methods for Canadian pipeline construction.

4.5 Pipeline Construction Execution

It was assumed that the pipeline work will be contracted in the following manner:

Construction:	Prime Pipeline Construction Contractor
NDE / ECDA:	Sub-contract to Prime Pipeline Contractor
Cabled Concrete FOB location:	Armourflex – Washington State, USA
Project office:	One site Office located in Fort Nelson, BC.

Pipeline contractors' fees for the administration of sub-contracts are included in the estimate at the rate of 5%.

A figure illustrating the Macro-Level Construction plan is provided in Appendix C.

5. Preliminary Schedule

It is estimated that the instream remediation will take 9 months to complete from design kick-off, DFO approvals, construction and site restoration. Instream activities can be completed in approximately 30 days; cabled concrete is of a marginally shorter installation duration as cabled concrete is more efficient to lay compared to loose rip rap.

It is assumed construction is not limited by restrictions within riparian management zones or restricted fisheries windows. Preference is to complete the project under low flow conditions.

6. Discussion

The risks associated with this estimate are related to the factors that are outside the construction execution plan such as:

- Extreme watercourse flow or flood conditions.
- Material availability or delays.
- Availability and experience of the construction crew for the duration of the construction.
- Additional environmental protection requirements.
- Regulatory permits and land availability delays; specifically the DFO Letter of Authority.
- Variations from expected site conditions and access.
- Changes in expected market competitiveness.
- Difficulty establishing water isolation when setting up instream cofferdams.

The aforementioned points are some examples of factors or potential risks that could affect the construction schedule, overall productivity of construction and material estimated costs. It is believed all of these risks would fall within the upper bound of the AACE Class 4 estimate (+50%).

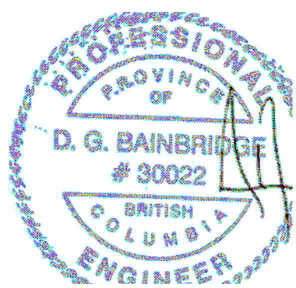
7. Closure

Remediation of the 168mm O.D. Fort Nelson transmission pipeline exposure at the Muskwa River is feasible based on preliminary hydrotechnical analysis by using instream rip rap (revetment) measures but is significantly more expensive compared to other pipe replacement options detailed within the Muskwa River Crossing FEED Study (03Mar10), as outlined in Appendix D.

It is recommended that the Muskwa River crossing be replaced by a horizontal directional drill based on a comparison of estimated capital costs.

Prepared by:

"David Bainbridge"



David Bainbridge, P.Eng
Pipeline Engineer
Chinook Engineering Ltd.

Appendix A

Cost Estimate Summary – D50:300mm Rip Rap

Appendix B

Cost Estimate Summary – Cabled Concrete Mats

Appendix C

Construction Plan

Appendix D

Project FEED Option Cost Comparisons

Appendix C

HOUSEHOLD FORMATIONS DATA FROM BC STATS

Household Formations Data from BC Stats - P.E.O.P.L.E 34								
Annual Population								
Local Health Area Identification	**Local Health Area**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
81	**Fort Nelson**	2487	2513	2541	2566	2593	2622	2646
	Percentage Growth		1.0%	1.1%	1.0%	1.1%	1.1%	0.9%

Source: 20 Year Account Forecast file

Appendix D

DRAFT FORMS OF ORDERS

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-XX-XX

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

DRAFT ORDER

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

and

An Application by Terasen Gas Inc. -
Fort Nelson Service Area
for Approval to Amend its Schedule of Rates

BEFORE:

(Date)

WHEREAS:

A. British Columbia Utilities Commission (the "Commission") Order No. G-147-09 approved the Terasen Gas Inc. Application for Deferral Account Treatment for 2010 for the Fort Nelson Service Area ("TG Fort Nelson"); and

B. Order No. G-147-09 approved the continuation of delivery rates as set by Order No. G-172-08 except that, effective January 1, 2010, the Revenue Stabilization Adjustment Mechanism ("RSAM") rider was to decrease to $0.037/GJ, the continuation of existing deferral accounts and the establishment of two new rate base deferral accounts (IFRS Transitional Deferral Account and ROE & Capital Structure Deferral Account), the disposition of which would be determined in a future revenue requirements application; and

C. On September 8, 2010, TG Fort Nelson submitted its 2011 Revenue Requirements Application seeking approval to recover a revenue deficiency of $295 thousand through a permanent increase in its delivery rates, effective January 1, 2011; and

D. The Application seeks approval to decrease the RSAM rate rider, effective January 1, 2011, from $0.037/GJ by $0.004/GJ for a total rate rider of $0.033/GJ; and

E. The Application also seeks approval of a new rate base deferral account, 2011 RRA Costs Deferral; and

F. The Commission established a Written Public Hearing Process and a Regulatory Timetable for review of the Application; and

A. The Commission has reviewed the Application and concludes that the requested changes as outlined in the Application should be approved.

NOW THEREFORE pursuant to Section 44.2, 58, 60 and 61 of the *Utilities Commission Act*, the Commission orders as follows:

1. TG Fort Nelson to recover the revenue deficiency of $295 thousand through a permanent increase in its delivery rates effective January 1, 2011, resulting in a margin increase of 20.37 per cent and revised rates as set out in the Application, Section 2.4 Tables 2-2 and 2-3.

2. The RSAM rider to be set at $0.033 effective January 1, 2011.

3. Continuation of existing deferral accounts and establishment of a new rate base deferral account for 2011 RRA Costs as described in Section 7.6 of the Application

4. Adoption of Accounting and Other Policy Changes consistent with the TGI 2010-2011 Negotiated Settlement Agreement as set out in Section 7 and 9 of the Application.

5. Approval of the proposed 2011 capital expenditures including $2.45 million of capital costs (excluding AFUDC) related to the Muskwa River Crossing Project.

6. TGI is to notify its customers in the Fort Nelson Service Area about the delivery rate and rate rider changes by a bill message.

7. TGI is to file amended Gas Tariff Rate Schedules for the Fort Nelson Service Area in accordance with this Order in a timely manner.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <MONTH>, 20XX.

BY ORDER

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-XX-10

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DRAFT ORDER

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

and

An Application by Terasen Gas Inc. -
Fort Nelson Service Area
for Approval to Amend its Schedule of Rates

BEFORE:

(Date)

WHEREAS:

A. British Columbia Utilities Commission (the "Commission") Order No. G-147-09 approved the Terasen Gas Inc. ("TGI") Application for Deferral Account Treatment for 2010 for the Fort Nelson Service Area ("TG Fort Nelson"); and

B. Order No. G-147-09 approved the continuation of delivery rates as set by Order No. G-172-08 except that, effective January 1, 2010, the Revenue Stabilization Adjustment Mechanism ("RSAM") rider was to decrease to $0.037/GJ, the continuation of existing deferral accounts and the establishment of two new rate base deferral accounts (IFRS Transitional Deferral Account and ROE & Capital Structure Deferral Account), the disposition of which would be determined in a future revenue requirements application; and

C. On September 8, 2010, TG Fort Nelson submitted its 2011 Revenue Requirements Application seeking approval to recover a revenue deficiency of $295 thousand through a permanent increase in its delivery rates, effective January 1, 2011; and

D. The Application seeks approval to decrease the RSAM rate rider, effective January 1, 2011, from $0.037/GJ by $0.004/GJ for a total rate rider of $0.033/GJ; and

E. The Application also seeks approval of a new rate base deferral account, 2011 RRA Costs Deferral; and

F. TG Fort Nelson considers that a written hearing process is appropriate for the review of the Application and proposes a regulatory timetable for the regulatory review process; and

G. The Commission considers that establishing a written public hearing and regulatory timetable for the registration of Intervenors and for the review of the Application is necessary and in the public interest.

NOW THEREFORE the Commission orders as follows:

1. The Application will be examined by a Written Public Hearing process, in accordance with the Regulatory Timetable for the hearing that is established and attached as Appendix A to this Order.

2. The Application, together with any supporting materials, will be made available for inspection at the TGI Office, 16705 Fraser Highway, Surrey, BC, V4N 0E8, at the Town of Fort Nelson municipal offices at 5319 - 50th Avenue South, Fort Nelson, BC and at the British Columbia Utilities Commission, Sixth Floor, 900 Howe Street, Vancouver, B.C., V6Z 2N3, and will also be made available on the TGI and Commission websites at www.terasengas.com and www.bcuc.com.

3. Intervenors and Interested Parties should register with the Commission, in writing or electronic submission, , by Friday, October 8, 2010. Intervenors should specifically state the nature of their interest in the Application, and identify generally the nature of the issues that they intend to pursue during the proceeding and the nature and extent of their anticipated involvement in the review process.

4. TGI Fort Nelson will publish in display-ad format, the Notice of Application and Written Public Hearing, attached as Appendix B, in the appropriate Fort Nelson local news publications, as soon as it is possible to do so.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <month>, 2010.

BY ORDER

Attachment

Terasen Gas Inc. -
Fort Nelson Service Area
Application for Approval of 2011 Revenue Requirements

REGULATORY TIMETABLE

ACTION	DATE (2010)
Publication of Notice	October 4 to October 15
Commission Information Request No. 1	Wednesday, October 6
Intervenor Registration	Friday, October 8
Intervenor Information Request No. 1	Wednesday, October 13
Terasen Fort Nelson Response to Information Requests No. 1	Thursday, November 10
Terasen Fort Nelson Final Argument Submissions	Thursday, November 18
Intervenor Final Argument Submissions	Thursday, November 25
Terasen Fort Nelson Reply Argument Submissions	Thursday, December 2

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Terasen Gas Inc.
Fort Nelson Service Area
Application for Approval of 2011 Revenue Requirements

NOTICE OF APPLICATION

THE APPLICATION

On September 8, 2010, Terasen Gas Inc. – Fort Nelson Service Area ("TG Fort Nelson" or the "Company") applied to the British Columbia Utilities Commission (the "Commission") for approval of its 2011 Revenue Requirements (the "Application") on a permanent basis, pursuant to Sections 58, 60 and 61 of the Utilities Commission Act (the "Act"), effective January 1, 2011. The Application seeks approval, on a permanent basis, effective January 1, 2011, to decrease the Revenue Stabilization Adjustment Mechanism ("RSAM") rate rider from $0.037/GJ by $0.004/GJ for a total rate rider of $0.033/GJ. The Application also seeks a revenue requirement increase of $295 thousand for the 2011 test year, effective January 1, 2011, resulting in an average of 20.37 per cent increase on a delivery margin basis for all customers.

THE REGULATORY PROCESS

The Commission has established a written process for submissions regarding the regulatory process for the review of the Application.

INTERVENTION

Persons who expect to actively participate in the Terasen Gas proceeding should register as Interveners with the Commission, and should identify the issues that they intend to pursue as well as the nature and extent of their anticipated involvement in the review process. Interveners will each receive a copy of the Application, all correspondence and filed documentation and should provide an email address, if available.

Persons not expecting to actively participate, but who have an interest in the proceeding, should register as Interested Parties. Interested Parties will receive a copy of the Executive Summary in the Application, and all Orders and Decisions issued.

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Interveners and Interested Parties should register in writing, no later than Friday, October 8, 2010. Notification by mail, courier delivery, fax or email is acceptable.

All submissions and/or correspondence received from active participants or the general public relating to the Application will be placed on the public record and posted to the Commission's website.

PUBLIC INSPECTION OF THE APPLICATION

The Application and supporting materials will be available for inspection at the following locations:

> **British Columbia Utilities Commission**, Sixth Floor, 900 Howe Street, Vancouver, BC V6Z 2N3
> Telephone: 1-800-663-1385 Internet**:** www.bcuc.com
>
> **Terasen Gas** Office, 16705 Fraser Highway, Surrey, BC V6N 0E8 Internet**:** www.terasengas.com
>
> **Town of Fort Nelson** municipal offices, 5319 -50th Avenue South, Fort Nelson, BC

For further information, please contact Ms. Erica M. Hamilton, Commission Secretary, as follows:

Telephone:	(604) 660-4700	Telephone:	(B.C. Toll Free) 1-800-663-1385
Facsimile:	(604) 660-1102	E-mail:	commission.secretary@bcuc.com