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November 12, 2010

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. - 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 (the "Application")

Response to the British Columbia Utilities Commission ("BCUC" or the "Commission") Information Request ("IR") No. 1

On September 8, 2010, Terasen Gas filed the Application as referenced above. In accordance with Commission Order No. G-149-10 setting out the Regulatory Timetable for the review of the Application, TG Fort Nelson respectfully submits the attached response to BCUC IR No. 1.

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

Yours very truly,

TERASEN GAS INC.

Original signed:

Diane Roy

Attachment

cc (e-mail only): Registered Parties

1.0 Reference: Executive Summary

Exhibit B-1, Section 1.2, p. 1

1.1 "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."

1.1.1 What amount/threshold does TGFN define as Material and how will this amount be determined.

Response:

TGFN does not believe that materiality can be generally defined as a specific amount or a threshold because the determination of whether a variance is "material" depends on the specific circumstances contributing to the variance and the effect on the customers' rates. TGFN believes that as a general rule, the materiality of a specific item should be considered in the context of its impact on customers' rates.

Specifically for the Muskwa River Crossing Project, TGFN has received the HDD Peak to Peak Option Class 3 estimate and has determined that the estimate is materially different than the amount included in the Application. TGFN plans to file an Evidentiary Update on November 19, 2010 reflecting updated information.

1.2 Please provide, on both a total and unbundled basis, a sample customer billing summary for an average TGFN customer in rate classes 1, 2.1, 2.2 and 25 with a direct comparison to how that customer's bill would appear if TGFN customers were billed as Terasen Gas Inc. (TGI) customers. Provide this information for 2009, 2010 and 2011 assuming rates applied for in this Application.

Response:

Please find in Attachment 1.2 (a), on both a total and unbundled basis, a customer billing summary for an average TG Fort Nelson customer in rate classes 1, 2.1, 2.2, and 25 if they were billed as TGI customers for years 2009, 2010 and 2011. Please note that the attached billing summary comparison is not reflective of TG Fort Nelson and TGI rates under a potential Terasen Utilities amalgamation scenario.

While responding to this IR, TG Fort Nelson found an error in Tables 2-2 and 2-3 (refer to Section 2, Page 10 and 11 of the Application). Column 2 ("Tariff @ 2010 rates") in Table 2-2 as filed in the Application excluded the RSAM Recovery Charge. Values were missing in Column 9 ("Add: Revised RSAM Recovery Charge") and Column 10 ("Tariff @ revised Rates Jan 1/11") of both Tables 2-2 and 2-3 of the Application. The revised corrected tables are attached with this response (see Attachment 1.2 (b)).

This results in a change to the Residential delivery rate referred to in Section 1, Introduction, Executive Summary and Background, subsection 1.6 on page 6 of the Application, from $2.75/GJ to $2.82/GJ.

Please note that these changes have no impact on the revenue deficiency of $295 thousand or the margin increase of 20.4% as requested for approval in the Application.

1.3 Please explain what factors have lead TGFN to require such a large rate increase for Rate Schedule 25 as a result of the increased revenue requirements.

Response:

Rate Schedule 25 is designed for the transportation customers and therefore only includes a delivery charge and not a commodity charge. If the commodity charges paid to the commodity supplier were included in the calculation, the percentage of rate increase for Rate Schedule 25 customers would be lower and more comparable to the increase for the residential and general service rates. As such, the factors that lead to the Rate Schedule 25 rate increase are the same as the factors that lead to the overall rate increase. As discussed in the Application (refer to Section 1.2, page 1), there are three major factors that contributed to the revenue deficiency of $295 thousand which translates into a 20.37% increase to the delivery margin:

1. Higher approved equity ratio for 2010 and 2011 and higher approved return on equity beginning July 1, 2009;
2. Changes to depreciation rates; and
3. Rate base growth driven by recent capital projects, including the Muskwa River Crossing.

TG Fort Nelson believes that 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.

2.0 Reference: RSAM

Exhibit B-1, Section 3.2.1, p. 11

"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."

2.1 Please clarify if the delivery rate used in this calculation is the actual or forecasted delivery rate.

Response:

The delivery rate used in this calculation is the delivery component of the approved bundled tariff rate for the year that the volume variance relates to.

2.2 Please provide the forecasted and actual TGFN delivery volumes in TJ for the past 5 years under Rate Schedules 1, 2.1, 2.2 and 25.

Response:

Below are the actual and forecasted delivery volumes in TJs for the past 5 years.

For Rate Schedules 1, 2.1 and 2.2, the volume variances are mainly due to the weather fluctuations compared to normal. For Rate Schedule 25, during 2009 the 2 customers ceased operations and the consumption of gas was just for space heating. The RSAM account continues to be an effective mechanism to address this volatility.

Fort Nelson Volumes (TJ)					
ACTUAL	**2005**	**2006**	**2007**	**2008**	**2009**
RATE 1 - Residential	259.7	266.0	275.0	278.9	282.7
RATE 2.1 - Small Commercial	194.1	183.6	193.4	192.6	199.1
RATE 2.2 - Large Commercial	95.9	94.1	92.4	90.5	92.8
RATE 25 - General Firm Transportation	369.9	345.6	264.1	206.7	71.4
Total	919.7	889.2	824.9	768.7	645.9
FORECASTED	**2005**	**2006**	**2007**	**2008**	**2009**
RATE 1 - Residential	301.9	291.1	300.1	291.2	270.5
RATE 2.1 - Small Commercial	195.0	202.6	212.7	209.9	195.0
RATE 2.2 - Large Commercial	93.6	104.8	107.0	96.0	88.4
RATE 25 - General Firm Transportation	402.8	379.9	350.3	276.1	13.7
Total	993.4	978.4	970.2	873.2	567.6

2.3 Does TGFN believe that it is fair to continue charging all customers an equal rate rider per GJ of gas delivered?

Response:

TG Fort Nelson believes it is fair to continue charging all customers an equal rate rider per GJ of gas delivered.

However, as mentioned in TG Fort Nelson's response to BCUC IR 1.7.4 in Terasen Gas Inc. Fort Nelson Service Area's 2004 Revenue Requirements Application, TG Fort Nelson is not opposed to having a class-specific rate rider.

TG Fort Nelson submitted the following response referred to above:

> *"While the Application was for a single RSAM rider to be applicable to all rate classes, Terasen Gas is not opposed to having a class-specific RSAM and separate rider for Rate 25. It is difficult to determine for Fort Nelson whether cross subsidization would be occurring or not in the case where one RSAM rider applies to all classes since there has never been a Fort Nelson Service Area rate design proceeding. However the*

Commission has historically ordered that the revenue deficiency arising from customer use rate changes or industrial revenue changes be shared across all rate classes in other service areas in British Columbia."

In Commission Order No. G-16-04, when approving the RSAM and RSAM interest deferral account in the same proceeding, the Commission stated the following[1]:

"... Fort Nelson submits that including Rate 25 customers in the RSAM is appropriate because of the high proportion of total load (approximately 30 percent) flowing to industrial customers; the industrial rate structure which causes revenue collection to be entirely volumetric; and the lack of diversity in the Fort Nelson industrial load (Application, p. A-3; Tab 7, pp.2-3)*."*

"... Fort Nelson is not opposed to a class specific RSAM and rate rider for Rate 25 customers, but argues that a single RSAM is consistent with past Commission determinations that rate increase arising from decreased demand from specific classes should not be "streamed back" to those classes (Final Argument, p. 4; Response to BCUC Staff IR No. 1, question 7.4)."

"The Commission approves the implementation of the RSAM account as applied for by Fort Nelson".

TG Fort Nelson believes it is fair to continue charging all customers an equal rate rider per GJ of gas delivered for the following reasons:

First, as stated in the response to BCUC IR 1.4.1, the customers under Rate 25 are Canfor's two operations, which are closed indefinitely. Since 2004 the industrial demand under Rate 25 has changed from using natural gas as an industrial process load to using natural gas for seasonal space heating, and the size of the load has decreased from 30% to 8% of the total TG Fort Nelson load. However, TGFN's revenues from the two Canfor operations in Fort Nelson are still significantly dependent on volumetric charges as in 2004, though the volume is now weather sensitive. Being a weather sensitive load is similar to residential and commercial customers albeit the Canfor operations have a much higher customer use rate.

Second, the industrial load in TG Fort Nelson is still undiversified.

Third, there has not been a Rate Design proceeding to determine if there is substantial cross subsidization, although Terasen Gas anticipates filing a comprehensive Rate Design that would include Fort Nelson in 2012.

[1] BCUC Order No. G-17-04, Appendix A, Pages 2 and 3 of 7.

Fourth, in the other TGI divisions the Commission has continued to approve a single rider charged to residential, commercial and industrial customers.

The RSAM rate rider as a proportion of the Industrial trailing block rate is only 1.5%. For the residential and commercial customers the RSAM rider as a proportion of the total rate is in the low range of approximately 0.4% in 2011, similar to 2006 and 2010. The RSAM rider is a minor component of the customers' total rate which does not merit any change at this time in how it is calculated. The ratio increased in 2007 and 2008 and peaked in 2009 due primarily to the load and revenue loss relative to forecast from the 2 Rate 25 Canfor operations in 2008. In 2009 the Rate 25 customers accounted for 65% of the gross offsetting credit to the RSAM deferral account ($109 thousand out of $165 thousand) which contributed to the reduction in the RSAM rate rider in 2010 and 2011. The following two tables shows the rate rider as a proportion of the total rate for residential, commercial and Rate 25 Transportation Service from 2006 through to forecast 2011, and the gross additions to the RSAM deferral by Rate Class from 2007 through projected 2010.

RSAM RIDER AS A % OF TOTAL CUSTOMER RATES

		2006 [1]			2007 [2]			2008 [3]			2009 [4]			2010 [5]			2011 [6]		
		RSAM Rider	Total Volumetric Rate	% of Total	RSAM Rider	Total Volumetric Rate	% of Total	RSAM Rider	Total Volumetric Rate	% of Total	RSAM Rider	Total Volumetric Rate	% of Total	RSAM Rider	Total Volumetric Rate	% of Total	RSAM Rider	Total Volumetric Rate	% of Total
Residential	Block 1	$ 0.039	$ 10.440	0.37%	$ 0.073	$ 9.000	0.81%	$ 0.114	$ 9.710	1.17%	$ 0.236	$ 11.740	2.01%	$ 0.037	$ 10.210	0.36%	$ 0.033	$ 10.540	0.31%
	Block 2	$ 0.039	$ 9.583	0.41%	$ 0.073	$ 8.143	0.90%	$ 0.114	$ 8.577	1.33%	$ 0.236	$ 9.876	2.39%	$ 0.037	$ 8.346	0.44%	$ 0.033	$ 8.201	0.40%
	Block 3	$ 0.039	$ 9.548	0.41%	$ 0.073	$ 8.108	0.90%	$ 0.114	$ 8.531	1.34%	$ 0.236	$ 9.818	2.40%	$ 0.037	$ 8.288	0.45%	$ 0.033	$ 8.132	0.41%
Rate 2.1 / 2.2	Commercial																		
	Block 1	$ 0.039	$ 14.800	0.26%	$ 0.073	$ 13.360	0.55%	$ 0.114	$ 15.500	0.74%	$ 0.236	$ 19.260	1.23%	$ 0.037	$ 17.730	0.21%	$ 0.033	$ 19.645	0.17%
	Block 2	$ 0.039	$ 9.724	0.40%	$ 0.073	$ 8.284	0.88%	$ 0.114	$ 8.764	1.30%	$ 0.236	$ 10.108	2.33%	$ 0.037	$ 8.578	0.43%	$ 0.033	$ 8.497	0.39%
	Block 3	$ 0.039	$ 9.682	0.40%	$ 0.073	$ 8.242	0.89%	$ 0.114	$ 8.708	1.31%	$ 0.236	$ 10.037	2.35%	$ 0.037	$ 8.507	0.43%	$ 0.033	$ 8.412	0.39%
T-Service	Block 1	$ 0.039	$ 1.131	3.45%	$ 0.073	$ 1.131	6.45%	$ 0.114	$ 1.501	7.59%	$ 0.236	$ 2.319	10.18%	$ 0.037	$ 2.319	1.60%	$ 0.033	$ 2.873	1.15%
	Block 2	$ 0.039	$ 1.049	3.72%	$ 0.073	$ 1.049	6.96%	$ 0.114	$ 1.392	8.19%	$ 0.236	$ 2.145	11.00%	$ 0.037	$ 2.145	1.72%	$ 0.033	$ 2.656	1.24%
	Block 3	$ 0.039	$ 0.856	4.56%	$ 0.073	$ 0.856	8.53%	$ 0.114	$ 1.136	10.04%	$ 0.236	$ 1.736	13.59%	$ 0.037	$ 1.736	2.13%	$ 0.033	$ 2.146	1.54%

1) Rates effective January 1, 2006
2) Rates effective January 1, 2007
3) Rates effective February 1, 2008
4) Rates effective January 1, 2009
5) Rates effective January 1, 2010
6) Rates Applied for January 1, 2011 (BCUC IR 1.2.1)

RSAM GROSS ADDITIONS BY RATE CLASS ($000's)

	2007	2008	2009	2010
Residential	$ 27.7	$ 12.4	$ (31.2)	$ 25.1
Small Commercial	25.6	27.6	(12.2)	0.3
Large Commerical	20.6	3.9	(12.4)	(0.4)
T-Service	75.1	79.9	(108.8)	26.5
Total	$ 149.0	$ 123.8	$ (164.6)	$ 51.5

3.0 Reference: Calculation of Rider 5 RSAM for 2011

Exhibit B-1, Table 2-4, p. 12

3.1 Please confirm that column 2 is NOT in thousands of dollars as indicated.

Response:

TG Fort Nelson confirms that the column heading was in error and should have been marked only as "$". The values in the column are **NOT** in thousand of dollars.

3.2 Please provide the detailed calculation of the rate rider indicating, by rate class how much of the deferral account TGFN forecasts to recover from customers?

Response:

The calculation of the RSAM Rider for 2011 is displayed in Table 2-4 of the Application, and further explained in the table below. The following table also shows that TG Fort Nelson forecasts to recover $19,738 of the pre-tax balance in the deferral account in 2011 (the difference from the $19,480 amount shown in Table 2-4 is due to rounding the RSAM rider to three decimal places).

Line No.	Customers	Rate Schedule	2011 Sales Volume GJ	RSAM Rider Unit $/GJ
1				$ 0.033
2				
3	Residential	1	263,401	$ 8,692
4	General Service			
5	Small Commercial	2.1	190,789	6,296
6	Large Commercial	2.2	94,391	3,115
7	General Firm Service T-Service	25	49,549	1,635
8				
9	Total		598,130	$ 19,738
10				
11	Projected December 31, 2010 RSAM & RSAM Interest Deferral Account Balance (After-tax)			$ 42,954
12				
13	2011 Amortization - 1/3 Projected Year End Balance			$ 14,318
14	Divide by 1 - Current Tax Rate		26.50%	73.50%
15	Required Pre-Tax Recovery			$ 19,480
16				
17	Annual Sales / T-Service Volumes			598,130
18	RSAM Rider Rate for 2011 $ / GJ			$ 0.033

Lines 11 through 18 above demonstrate how the RSAM rider is derived pursuant to Commission Order No. G-17-04, Appendix A, pages 2 and 3. The derivation of the Rate Rider is to be one third of the prior year ending balance grossed up to a pre-tax value divided by the volumes for Rate Schedules 1, 2.1, 2.2, 3.1, 3.2, 3.3 and 25. For 2011 there are no forecast volumes for Rate Schedules 3.1, 3.2 and 3.3. The derived Rate rider (as shown on Line 18 and Line 1) is then multiplied by each Rate Class sales or transportation volumes to derive the class RSAM recovery amount (Lines 3 through 7).

3.3 Please explain how and when the tax deduction resulting from the costs underlying the deferred expenses will benefit ratepayers and how it has been taken into account in this revenue requirements application.

Response:

For most items that are recovered through revenue requirements, the revenue is collected and the expense is incurred in the same year. Therefore, TG Fort Nelson pays tax on the revenue and obtains a tax benefit for the expense in the same year. In these cases, there is no tax impact on the revenue requirement calculation. The main items that affect the calculation of tax in the determination of revenue requirements are the equity return and timing differences in the deduction of expenses for revenue requirements versus tax purposes.

In the case of most deferral accounts (using a deferred charge as an example), the expense is deducted by TG Fort Nelson in the year the expenditure is incurred, but the revenues are not collected from customers (and therefore taxable to TG Fort Nelson) until they are included in rates through amortization expense. To compensate customers for TG Fort Nelson having deducted the expense for tax purposes in advance of paying the taxes on the related revenues, deferral accounts are generally recorded on a net-of-tax basis, reducing the rate base and the calculation of the earned return for the benefit of customers.

This treatment was approved in Commission Order No. G-53-94, dated August 4, 1994, Re: Regulatory Accounting Guidelines for Natural Gas Utilities, Item 3, which states:

> *"If deferred expenses or credits are included in the utility's actual tax calculation in the year they are first recorded, then the amounts shall be recorded in rate base on a net of tax basis. If such expenses or credits are not included in the utility's tax calculation then the amounts shall be on a before tax basis."*

In compliance with the Order, TG Fort Nelson has been recording its tax-deductible deferred charges and taxable deferred credits on a net-of-tax basis.

The RSAM account specifically captures the difference in the timing of when revenues are received rather than when expenses are recovered, but the principle is the same. Also, the RSAM account is recovered via a rider, whereas most deferral accounts are recovered through amortization expense. Again, there is no difference in the impact on customers' rates for amortizing a deferral account versus recovering through a rider. Riders are recovered from customers on a pre-tax basis and included in the taxable income for TG Fort Nelson at that time; amortization expense is also recovered from customers on a pre-tax basis and included in taxable income for TG Fort Nelson at that time.

4.0 Reference: Underlying Assumptions

Exhibit B-1, Section 3.3, p. 14

"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 percent of the TGFN 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."

4.1 Does TGFN consider it a possibility that its requested rates for Rate Schedule 25 may directly result in a loss of load delivered to that single customer?

Response:

Please see the response to BCUC IR 1.4.2.

4.2 Has TGFN engaged in any dialogue with that customer regarding this Application to accurately estimate how load may be impacted by the requested increase?

Response:

Yes, TG Fort Nelson has engaged in dialogue with the customer regarding this Application. Since Canfor's two locations in Fort Nelson are both closed indefinitely and Canfor is consuming gas only for space heating to prevent damage to their assets, Canfor's consumption at the sites will be solely weather-driven. The load will not change as a result of the requested increase.

4.3 If TGFN was to lose a significant amount of load associated with Rate Schedule 25, how would this loss impact the RSAM and future remaining rate payers? Provide a sensitivity analysis to demonstrate how a loss of 1 percent of total TGFN demand would impact revenue requirements and rate riders for all other customers for 3 years after such a loss.

Response:

In answering this question, TG Fort Nelson is assuming that the load loss is a permanent load loss, and under two different scenarios.

First, if the load loss is realized after rates have been set for 2011 based on the filed Application, the following analysis holds true.

A 1% load loss equates to a 6.0 TJ reduced volume, which would result in a loss of $12.8 thousand in revenues, and would cause an increase in the margin portion of rates of 0.74% for 2012. It would also increase the RSAM rider by an average of $0.005 / GJ over the 3 years from 2012 through 2014. Should the load actually permanently increase from forecast then there would be an opposite effect on rates.

The table below shows the volume loss from a 1% reduction in the total TG Fort Nelson volume, assumed to come from Rate 25 customers. The reduced volumes are assumed to be applicable to the block rates for volumes greater than 280 GJ and were priced at the applied for rate (Table 2-2 Proposed Tariff Rate Change and Rate Class Revenue Recovery, page 10) of $2.146 /GJ. In responding to this question TG Fort Nelson has assumed the total revenue requirement from 2011 would remain unchanged in order to capture the volume change effect only and not any other changes that may cause changes to the revenue requirements in 2012 and beyond. To measure the impact on RSAM TG Fort Nelson has treated the reduced revenue effect as a before tax charge to the deferral account in order to compare RSAM rates for 2012 through 2014 and used the reduced volume to derive the rider from a reduced load. This is compared to a derived rider based on the Forecast balance in the Application (Tab 9, Schedule 6.1, Column 9, Lines 16 and 17).

Second, if we assume the load loss as part of the determination of rates for 2011, it would increase the deficiency by $10.4 thousand (6 TJ x $1.736 / GJ (Rate 25 existing trailing block rate)). This would cause the deficiency to increase from $295 to $305 thousand; and the margin increase to be 21.2% ($305 / ($1,448 - $10)[2]. There would be no impact on the RSAM rates as the reduced volume is not large enough to cause the rate to round up higher ($19,480 / (99% of 598.1) = $0.033).

[2] $1,448,000 is the gross margin at existing rates; Tab 9, Schedule 1, Line 8, Column 3.

Impact on Rates 2012 if Load Loss Occurs Ex Ante of Setting 2011 Rates

Line No.	Impact of Decreased Load on Rates & RSAM Rider								
1	**Decreased Volume From Forecast**								
2	Total Sales / T-Service Forecast (TJ)		598.1						
3	1% Load Loss		(6.0)						
4	Adjusted Sales / T-Service Volumes (TJ)		592.1						
5									
6	**Decreased Revenues ($000's)**								
7	Revenues at Revised Rates - 2011		$4,921.3						
8	Less: Cost of Gas		(3,178.6)						
9	Gross Margin at Revised Rates - 2011		1,742.7						
10	Revenue Loss From Rate Schedule 25								
11	1% Load Loss (TJ)	(6.0)							
12	Rate Schedule 25 Applied for Rate Block 3	$ 2.146							
13	Reduced Revenue		(12.8)						
14	Adjusted Reduced Gross Margin		$1,729.9						
15									
16	**Future Revenue Deficiency as a % of Adjusted Reduced Gross Margin**		**0.74%**						
17									
18	**RSAM Rates if no Load Loss for 3 Years**								
19	Forecast RSAM Balance December, 2011		$ 28	Tax Rate	Pre-Tax Recovery	Volume (TJ)	RSAM Rate $/GJ	RSAM Rate increase	
20	2012 Amortization		(9.3)	25%	12.4	598.1	$ 0.021		
21	2013 Amortization		(6.2)	25%	8.3	598.1	$ 0.014		
22	2014 Amortization		(4.1)	25%	5.5	598.1	$ 0.009		
23									
24	**RSAM Impact on Rates for next 3 Years if Reduced Load Incurred in 2011**								
25	Gross Addition to RSAM		$ 12.8						
26	Tax Offset	26.50%	(3.4)						
27	Net Addition		9.4						
28	Revised RSAM Balance December, 2011		$ 37.4						
29	2012 Amortization		(12.5)	25%	16.6	592.1	$ 0.028	**$ 0.007**	
30	2013 Amortization		(8.3)	25%	11.1	592.1	$ 0.019	**$ 0.005**	
31	2014 Amortization		(5.5)	25%	7.4	592.1	$ 0.012	**$ 0.003**	

4.4 Does TGFN believe there are options to mitigate such a significant rate increase for Rate Schedule 25?

Response:

The deficiency has been applied evenly to all customers based on the margin (revenue minus cost of gas) at existing rates and the total deficiency; i.e. 20.37%. The Commission has consistently approved this methodology for Terasen Gas Inc. (3 Divisions) and for TG Fort Nelson since the early 1990's. Mitigating the rate increase for Rate Schedule 25 would require the costs to be borne by other customers, resulting in larger increases for other customers. TG Fort Nelson believes that in the current circumstances, the increase should be applied to all customers in the normal course.

5.0 Reference: Customer Growth

Exhibit B-1, Table 3-2, p. 15

5.1.1 Please provide a comparison of estimated 2010 customer growth for Rate Schedules 1, 2.1 and 2.2 to actual growth year to date. Also, provide actual customer growth amounts for each of these classes as of September 30, 2010.

Response:

The following table shows the comparison of monthly estimated 2010 customer growth for Rate Schedules 1, 2.1 and 2.2 to actual growth up to September 30, 2010, which reflects the latest available information. As shown in the following table, although individual months vary, the actual customer additions are tracking very closely to the forecast additions so far in 2010. The average variance between the forecast and actual figures is approximately 0.9%.

TGFN 2010 Monthly Customer Growth

Actual	January	February	March	April	May	June	July	August	Sept.	Year to Date
Rate 1	0	3	-1	-7	-6	-11	-5	0	14	-13
Rate 2.1	0	-1	1	-1	-1	-2	0	0	1	-3
Rate 2.2	0	0	0	0	0	0	-1	0	1	0
Total	**0**	**2**	**0**	**-8**	**-7**	**-13**	**-6**	**0**	**16**	-16

Forecast	January	February	March	April	May	June	July	August	Sept.	Year to Date
Rate 1	3	-2	0	-11	-5	-4	4	5	10	0
Rate 2.1	1	-1	-1	0	-1	-2	2	3	-3	-2
Rate 2.2	0	0	0	0	0	0	0	0	0	0
Total	**4**	**-3**	**-1**	**-11**	**-6**	**-6**	**6**	**8**	**7**	-2

6.0 Reference: Use Per Customer

Exhibit B-1, Table 3-3, p. 16

6.1 Does TGFN not take into account weather forecasts when making estimates of future use per customers?

Response:

TG Fort Nelson does not take into account specific weather forecasts when making future use per customer estimates. TG Fort Nelson's residential and commercial use per customer forecasts are prepared assuming the region being forecasted will experience normal weather for the analysis period.

By forecasting on a weather-normalized basis, TG Fort Nelson removes the impacts that short term weather fluctuations have on annual demand. Additionally, when comparing the current forecast to other years, the normalized demand approach allows for the identification and analysis of trends resulting from other factors, such as efficiency improvements and changes in the housing mix.

This methodology is consistent with the approach taken in prior years, is an accepted industry standard and has been reviewed and accepted both internally and by the BCUC.

6.2 Does TGFN not take into account commodity prices of natural gas when making estimates of future use per customer?

Response:

TG Fort Nelson does not use commodity price as a driver of demand mainly for two reasons.

First, although it is recognized that customers do change their short-term behavior when faced with sudden and significant commodity cost increases, long-term changes in use per customer rates for mature gas utilities are more a function of advances in heating technology and home construction techniques, both of which improve on an ongoing basis irrespective of natural gas prices. Sudden increases in natural gas prices may accelerate the decision to purchase more efficient equipment, but once that purchase has been made the impact on consumption (related to the new equipment) is permanent regardless of whether prices later moderate.

Second, it is difficult to isolate demand responses to only price.

6.3 How do weather forecasts for the winter of 2010 compare to weather forecasts of the winter of 2009?

Response:

Preliminary winter weather forecasts[3] for 2010 are citing a moderate to strong developing La Nina in the Pacific Ocean. This is expected to result in a colder and wetter winter than normal for British Columbia and the US Pacific Northwest as a whole. The long range winter 2009 forecast identified a strong El Nino effect and predicted a warmer and drier winter than normal. The long range 2009 forecast was proven correct last winter, although TG Fort Nelson has not performed an analysis of the predictive value of weather forecasts over either the short or long term.

Please refer to the response to BCUC IR 1.6.1 for a discussion of why normalized weather is the preferred and recognized forecasting approach for natural gas utilities.

6.4 How does the use per customer estimates of TGFN compare to those of TGI for the same period? Include both total volume in GJ as well as annual growth rates for 2007 to 2010.

Response:

The tables below show a trend of declining use per customer for all TGI and TGFN customers over the four year period, except for TG Fort Nelson Rate 2.2. Please see the response to BCUC IR1.6.6.2 for a discussion of the specific events responsible for the Rate 2.2 increase in use per customer.

TGI Use Per Customer (per GJ/annum)

	2007	2008	2009	2010
	Normal	Normal	Normal	Forecast
Rate 1	96	93	93	87
Rate 2	317	326	322	311
Rate 3	3,426	3,406	3,369	3,324

[3] Source: Environment Canada

TGFN Use Per Customer (per GJ/annum)

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

TGI Use Per Customer Growth

	2007	2008	2009	2010
	Normal	Normal	Normal	Forecast
Rate 1		-3.1%	0.0%	-6.5%
Rate 2		2.8%	-1.2%	-3.4%
Rate 3		-0.6%	-1.1%	-1.3%

TGFN Use Per Customer Growth

	2007	2008	2009	2010
	Normal	Normal	Normal	Forecast
Rate 1		-1.4%	-1.4%	-0.7%
Rate 2.1		-4.9%	3.3%	-0.4%
Rate 2.2		1.7%	7.5%	0.0%

6.5 In Rate Schedule 2.1, use per customer declined in 2008 however, actually increased in 2009. Projections for 2010 indicate relatively consistent results.

6.5.1 Please update the 2010 forecast amounts based on actual results.

Response:

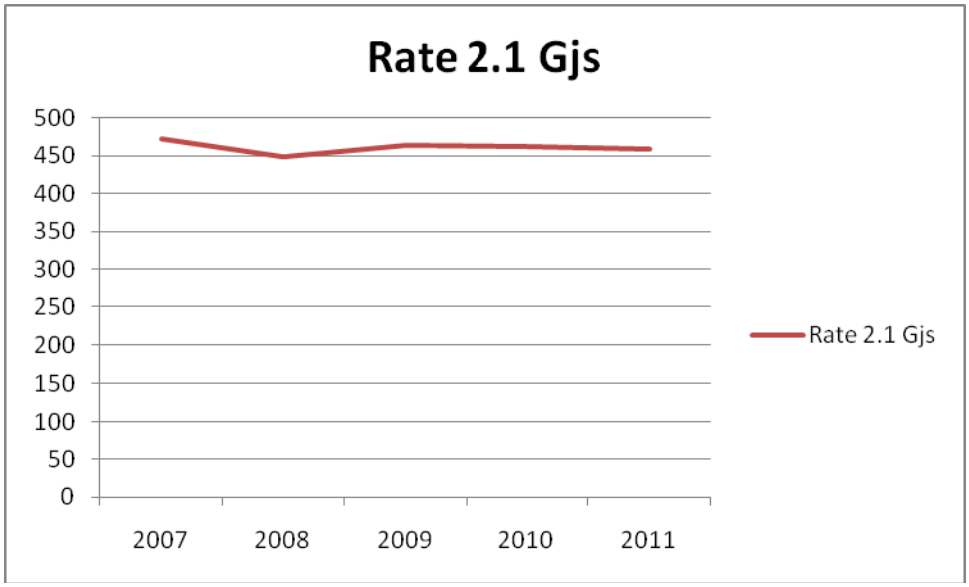
TG Fort Nelson is unable to provide an update incorporating actual results since the 2010 actual data has not yet been normalized. Given the year-to-date customer addition results as reported in response to BCUC IR1.5.1.1, TG Fort Nelson believes that the forecasts are still reasonable and that a forecast update would not provide substantially different information. Further, any variances between forecast and actual use rates will be captured in the RSAM deferral account for future refund to, or recovery from, customers.

6.5.2 Please explain why the trending in pattern is held flat despite a historical growth pattern displayed in the last 2 years?

Response:

The trend for rate 2.1 is analyzed based on three years, rather than two years, of data. The three year (2007-2009) average use rate is 462 GJ/yr, which also matches the 2010 projected use per customer. Based on the three years of data, TG Fort Nelson assumes a relatively stable, but slightly decreasing, use rate going forward.

We do note however that there is a measured average decrease of 8 GJ/customer (1.7%) over the three year period (2007-2009).



6.5.3 Please explain how it is reasonable to expect a decrease in use per customer in both 2011 and 2012 given the growth rate between 2007-2009.

Response:

Please see the response to BCUC IR 1.6.5.2.

6.6 In Rate Schedule 2.2, actual use per customer has risen steadily between 2007-2009. However, 2010 forecasts indicate consistent results in the year.

6.6.1 Please update the 2010 forecast amounts based on actual results.

Response:

Please see the response to BCUC IR1.6.5.1.

6.6.2 Please explain why the trending in pattern is held flat despite a historical growth pattern displayed in the last 2 years?

Response:

The increase in use per customer presented in Rate Schedule 2.2 for 2008 and 2009 was due to a few Rate 2.2 customers whose consumption showed significant one-time increases during the first quarter of 2008.

- A restaurant re-opened after being closed for over a year.
- A commercial customer re-opened after being closed for almost a year.
- Hotels were busier than during the previous year.

The change in these customers' annual use rates caused an increase to the overall Rate 2.2 use per customer in 2008, with a full year impact for the first two customers being reflected in 2009. Given that these increases are not considered long-term trends or expected to reoccur in 2011, we hold the use per customer forecast stable over the forecast period.

6.6.3 Would TGFN be willing to update their forecast for 2011 and 2012 to reflect the average growth rate experienced between 2007-2010? If not, please explain why this period is not reflective of normal operations.

Response:

TG Fort Nelson does not believe there is a basis on which to require an updated forecast. As described in BCUC IR 1.6.6.2, there were several one-time events in 2008 that caused the

increase in use per customer, and the overall trending pattern, excluding these one-time events, is relatively flat.

Also, please note that variances between the forecast and actual use per customer are captured in the Revenue Stabilization Adjustment Mechanism (RSAM) account for return to, or recovery from, customers in future years.

7.0 Reference: Declining Energy Demand

Exhibit B-1, Table 3-4, p. 17

7.1 Please explain why annual energy use of Rate 25 customers is projected to drop from 69TJ to 52TJ between 2009 and 2010.

Response:

2010 consumption for Rate 25 was down 12 TJ compared to 2009 for the January-August timeframe, based on actual (non-normalized) results. Based on this trend, TG Fort Nelson is projecting an additional reduction of 5 TJ for the period September-December.

Please also see the response to BCUC IR 1.4.2.

7.2 Please explain why annual energy use of Rate Schedule 25 customers is forecast to be 50TJ in 2011 despite actual results in 2009 of 69TJ.

Response:

Rate 25 customer's consumption is now partially weather dependent, and will therefore fluctuate from year to year in line with weather patterns.

In a discussion with the TG Fort Nelson Regional Manager, the Rate 25 consumption pattern is not expected to change for the duration of the forecast. Based on actual consumption through August of this year, the 2010 projected demand for Rate 25 is now trending towards 52 TJ, consistent with the data shown in Table 3-4. Based on the actual consumption data and a discussion with the TG Fort Nelson Regional Manager, TG Fort Nelson believes that the 2011 forecast consumption is reasonable.

7.3 Would TGFN consider an average consumption rate of 2009 and 2010 to be a better predictor of 2011 energy consumption over 2010 forecast results only?

Response:

TG Fort Nelson analyzes a three-year period to identify trends to be applied on a go-forward basis. Where no clearly defined trend exists, we then rely upon an average of historical consumption which may include a period of one to three years. The forecast is then validated

through market information (where available), internal discussions, and, where feasible, feedback from the customers themselves (eg. Industrial Survey). It is through this process that TG Fort Nelson develops additional confidence in its forecasts.

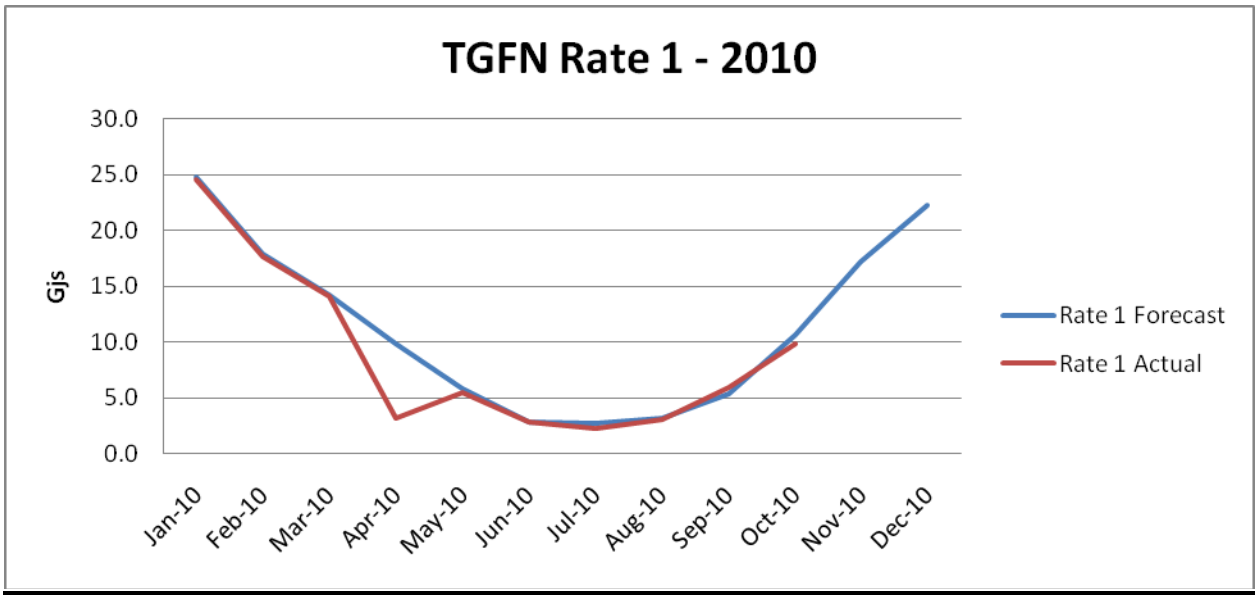
In the case of Rate Schedule 25, based on TG Fort Nelson's understanding of the situation at Canfor where space heating usage commenced part way through 2009, TG Fort Nelson believes that the most recent data (2010) does provide a better indication of future usage.

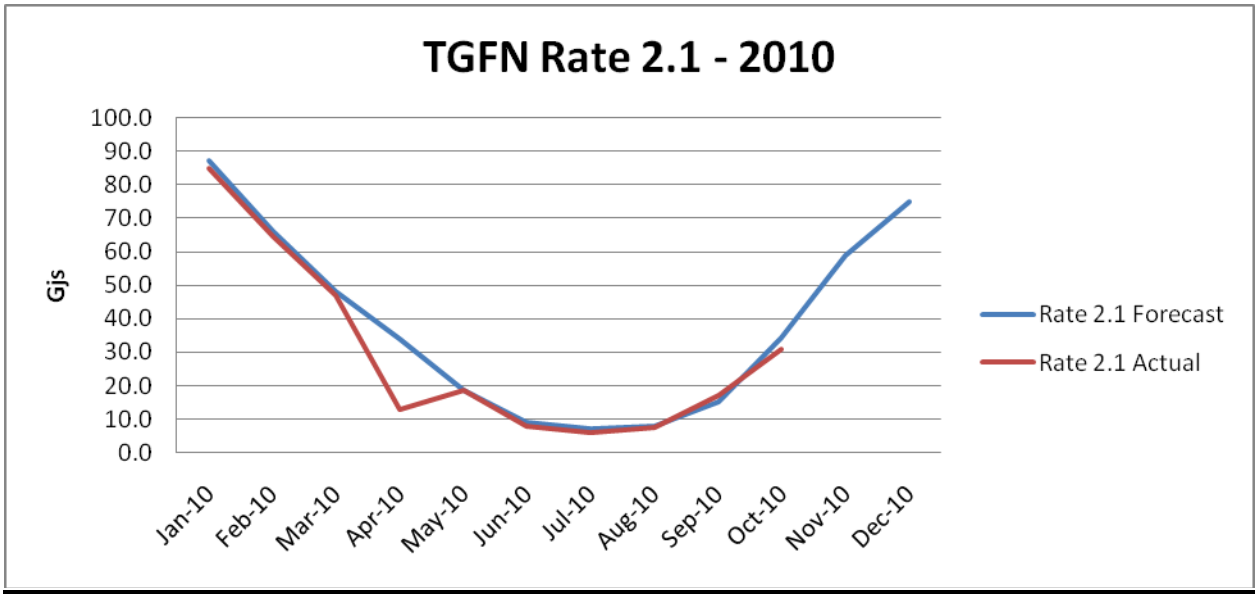
7.4 Please provide actual/projected customer usage rates for 2010 by month and compare these amounts to the forecast 2010 usage rates by month.

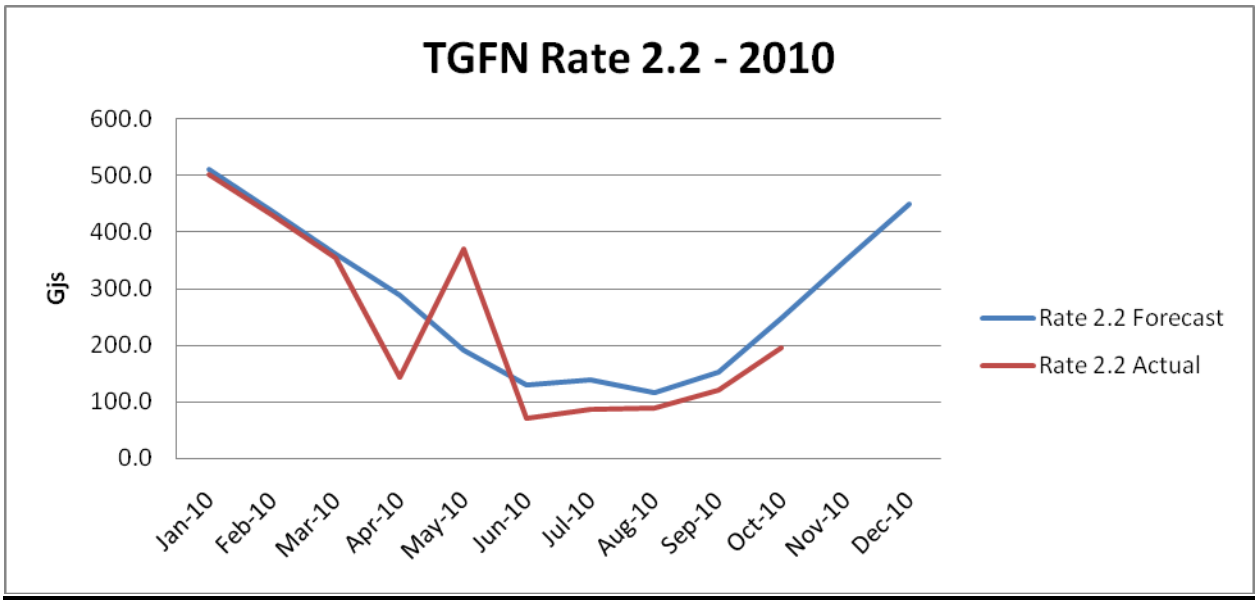
Response:

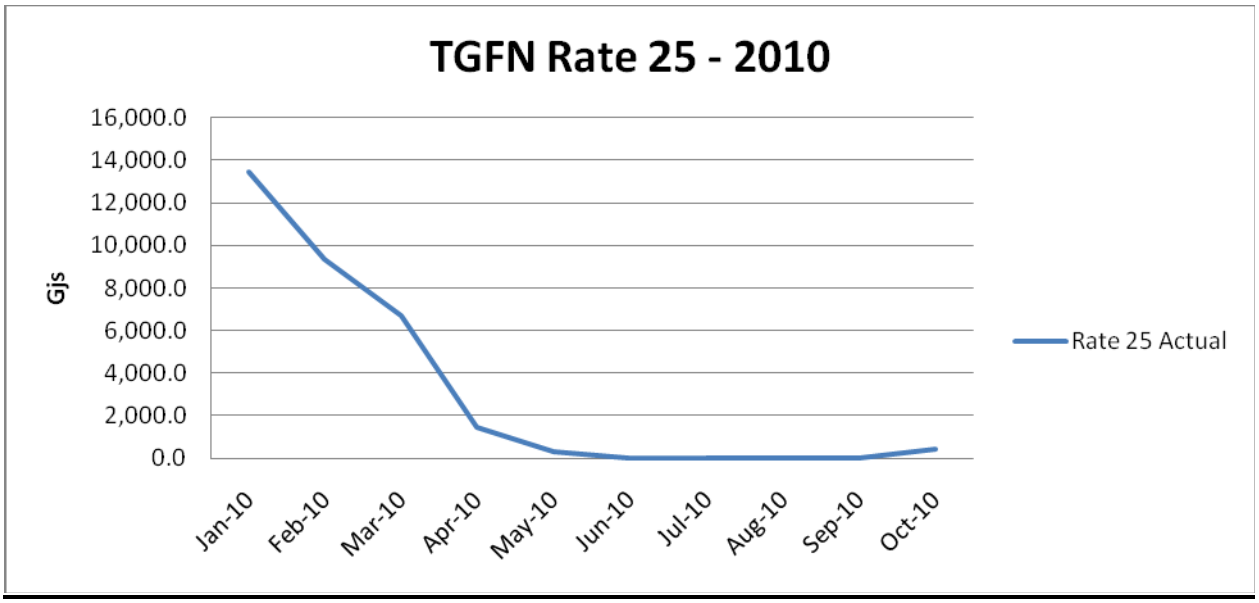
The monthly actual and forecast use per customer by rate class for 2010 is shown below. TG Fort Nelson does not develop use rates for industrial customers. Instead, total energy consumption (GJs) is shown for the Rate 25 Industrial customers. Charts for each rate class are provided to show the comparison between forecast and actual values.

		Monthly Use Rate - Gjs											
		Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Rate 1	Forecast	24.8	17.8	14.2	9.9	5.8	2.8	2.8	3.2	5.4	10.7	17.2	22.3
	Actual	24.5	17.7	14.1	3.2	5.5	2.8	2.2	3.1	6.0	9.9	N/A	N/A
Rate 2.1	Forecast	87.3	66.3	48.1	33.9	18.6	9.1	7.2	7.9	15.2	34.3	59.0	75.1
	Actual	85.1	64.6	46.9	12.8	18.6	7.7	5.9	7.3	17.1	30.9	N/A	N/A
Rate 2.2	Forecast	511.2	435.6	360.2	288.7	190.7	130.1	140.1	115.8	152.1	247.0	349.6	450.0
	Actual	502.7	428.4	354.2	143.4	369.7	72.0	87.1	88.6	120.0	194.9	N/A	N/A
Rate 25	Actual[1]	13,426.6	9,366.8	6,671.7	1,476.2	323.9	1.2	1.9	0.0	0.0	415.3	N/A	N/A
	[1] Total demand shown												


TGFN Rate 1 - 2010
Gjs
30.0
25.0
20.0
15.0
10.0
5.0
0.0
Jan-10
Feb-10
Mar-10
Apr-10
May-10
Jun-10
Jul-10
Aug-10
Sep-10
Oct-10
Nov-10
Dec-10
Rate 1 Forecast
Rate 1 Actual


TGFN Rate 2.1 - 2010
Gjs
100.0
90.0
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
Jan-10
Feb-10
Mar-10
Apr-10
May-10
Jun-10
Jul-10
Aug-10
Sep-10
Oct-10
Nov-10
Dec-10
Rate 2.1 Forecast
Rate 2.1 Actual


TGFN Rate 2.2 - 2010
600.0
500.0
400.0
300.0
200.0
100.0
0.0
Gjs
Jan-10
Feb-10
Mar-10
Apr-10
May-10
Jun-10
Jul-10
Aug-10
Sep-10
Oct-10
Nov-10
Dec-10
Rate 2.2 Forecast
Rate 2.2 Actual


TGFN Rate 25 - 2010
16,000.0
14,000.0
12,000.0
10,000.0
8,000.0
6,000.0
4,000.0
2,000.0
0.0
Gjs
Jan-10
Feb-10
Mar-10
Apr-10
May-10
Jun-10
Jul-10
Aug-10
Sep-10
Oct-10
Rate 25 Actual

7.5 Please provide actual/forecast volumes, by month, for 2009, 2010 and 2011 that are used in Table 3-4 and separately show the normalizing adjustments for each year.

Response:

The following tables provide the actual and forecast volumes by month for 2009 through 2011. Actual volumes and normalization factors are shown through October 2010. Please note that variances in usage are captured in the Revenue Stabilization Adjustment Mechanism deferral account, for future recovery from, or return to, customers.

FTN Normalized Volumes (TJ) 2009

		Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
R1	Actual	43	36	31	18	12	5	7	6	10	20	33	44
	Forecast	46	40	37	19	11	6	5	6	10	21	33	42
R2.1	Actual	32	28	19	16	9	3	4	4	6	13	24	32
	Forecast	34	31	23	17	6	5	2	3	6	13	22	28
R2.2	Actual	17	14	11	8	5	2	3	3	0	7	11	13
	Forecast	18	15	13	8	5	4	3	4	7	6	10	11
R25	Actual	18	13	12	2	0	0	0	0	0	3	9	12
(Not normalized)	Forecast	17	12	11	2	0	0	0	0	0	2	4	5

FTN Normalized Volumes (TJ) 2010

		Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
R1	Actual	47	36	34	7	10	6	5	6	10	22	N/A	N/A
	Forecast	48	35	28	19	11	5	5	6	10	21	33	43
R2.1	Actual	35	28	25	6	7	3	3	3	6	15	N/A	N/A
	Forecast	36	27	20	14	8	4	3	3	6	14	25	31
R2.2	Actual	14	13	12	4	10	2	2	2	3	6	N/A	N/A
	Forecast	14	12	10	8	5	4	4	3	4	7	10	12
R25	Actual	13	9	7	1	0	0	0	0	0	0	N/A	N/A
(Not normalized)	Forecast	14	12	10	8	5	4	4	3	4	7	10	13

FTN Normalized Volumes (TJ) 2011

		Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
R1	Forecast	45	35	31	19	11	5	5	6	10	20	33	43
R2.1	Forecast	36	25	25	14	7	4	3	3	6	14	24	30
R2.2	Forecast	13	13	12	8	5	4	4	3	4	7	10	12
R25	Forecast	12	9	8	2	0	0	0	0	0	2	6	10

2009 Normalization factors

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
R1	1.069	1.105	1.191	1.027	1.115	1.038	0.989	0.868	0.768	1.116	1.038	1.061
R2.1	1.058	1.095	1.183	1.032	1.144	1.051	0.985	0.827	0.718	1.130	1.036	1.053
R2.2	1.025	1.054	1.123	1.009	1.071	1.011	0.981	0.902	0.816	1.080	1.014	1.023

2010 Normalization factors

	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
R1	1.016	0.939	0.791	0.866	1.022	0.970	0.898	0.944	1.097	0.863	N/A	N/A
R2.1	1.013	0.944	0.789	0.845	1.028	0.959	0.859	0.925	1.121	0.846	N/A	N/A
R2.2	1.009	0.958	0.837	0.896	1.016	0.982	0.941	0.965	1.069	0.891	N/A	N/A

8.0 Reference: Gross O&M Per Customer

Exhibit B-1, Table 5-2, p. 23

8.1 What is the Gross O&M per customer in 2007, 2008 2009 and expected for 2010?

Response:

Please refer to the table below, showing gross O&M in total and per customer for the requested years. Please also refer to Table 5-1 of the Application for further detail on the 2009 and 2010 figures.

	Particulars	Actuals[1]			Projection
		2007	2008	2009	2010
1	Gross O&M (in '000's)	$ 835	$ 740	$ 784	$ 806
2	Average Number of Customers	2,340	2,355	2,355	2,365
3					
4	Average O&M per Customer	$ 357	$ 314	$ 333	$ 341
5					
6	[1]2007, 2008, and 2009 gross O&M is based on actuals and not the approved O&M.				

9.0 Reference: Transmission Mains

Exhibit B-1, Section 7.3.1, p. 31

9.1 "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."

9.1.1 What is the remaining useful life of the existing single 114 transmission pressure pipeline and what was its original cost?

Response:

The original Muskwa River Crossing was completed in 1960 with various significant upgrades to the pipeline in subsequent years. According to our records, the original cost for the pipeline was approximately $0.6 million, and the remaining depreciable life of the existing transmission pressure pipeline is approximately 26 years. Historical depreciation has been calculated on a straight-line basis by applying the approved depreciation rate of 2 percent to the original cost of the asset.

As explained in the response to BCUC IR 1.9.1.2, the remaining physical life of the asset depends on the probability of many factors that are beyond the control of TGFN, and estimating the probability of any of these events occurring is very difficult.

Please also refer to the response to BCUC IR 1.12.3 for further discussion of useful lives.

9.1.2 If nothing was done, how long does TGFN estimate that the existing pipeline would remain operational?

Response:

Specifically with regard to river crossings, it is difficult to predict the length of time an exposed pipeline will withstand river currents and debris moving along with the current.

There are two main factors that may affect the operation of the existing pipeline crossing the Muskwa River:

First, significant river currents may cause the pipe to oscillate which could lead to metal fatigue. Whether the pipe remains operational depends on the degree of oscillation and the quality of the pipe material.

Second, the water flow in the Muskwa River is able to move large cobbles along, which may strike the pipe and cause damage to the pipe coating. If the coating is damaged, corrosion will occur over time and a leak may occur eventually. The cobbles may also dent the pipe or cause the failure of the pipe if the pipe is struck hard.

Estimating the probability of any of these events occurring is very difficult; nevertheless, there remains the possibility that, due to the forces imparted on the pipe or the material moving in the river, the pipe may fail at any time.

9.2 "Total project costs for this option are currently estimated at $2.45 million (excluding AFUDC)."

9.2.1 Recognizing that TGFN has only conducted a class 4 cost estimate, please provide a detailed breakdown of cost estimates by cost category.

Response:

Please see Attachment 21.1 which has been submitted in response to BCUC IR 1.21.1. Attachment 21.1 includes the information on each of the alternatives that was inadvertently omitted from Appendix A of the Application. Specifically for the HDD Option, Appendix B-2 provides a cost analysis, by work breakdown structure (WBS).

For each Option, estimates are presented by category: Construction Services, Engineering and Inspection, Commissioning and Materials. Each line item within each category is either a unit rate or lump sum and summarizes estimates developed by a detailed construction plan and estimating procedure. The total included in the appendix is the Class 4 mean estimate.

The total cost included in the Application of $2.45 million consists of the Appendix B-2 HDD Peak to Peak Option Class 4 mean estimate of $1.643 million, plus $0.407 million (25%) to provide for potential additional costs (due to the uncertainty of the information at the time of application), plus $0.3million for project development and alternative evaluation costs, plus $0.1 million for site remediation and potential ongoing completion costs.

9.2.2 Recognizing that TGFN has only conducted a class 4 cost estimate and noting comments in section 4.4 of Appendix A, please confirm that a general contingency allowance of 15% of all project costs has been included in the estimate and that no other management reserves and cost inflators (including inflation) are included in the calculation.

Response:

In the "Front End Engineering Design" study included as Appendix A of the Application, a contingency of 15% has been included for each option to account for miscellaneous services, materials, shipping and labour. No cost escalation or inflation factors were employed in these estimates. (See section 4.4 of the Appendix A study.)

The $2.05 million for "HDD installation and allowance for cost escalation" in Table 7-4 (page 40 of the Application) accounts for the mean value of the HDD Peak to Peak Option Class 4 estimate, plus 25%. See also BCOAPO IR 1.10.6 for further discussion of the mean plus 25% estimate.

9.2.3 What are the risks that the cost may exceed these estimates and how has TGFN responded to these risks?

Response:

Major risk factors for the HDD Options include:

Risk #1 - Construction

- Risk: Failure of the horizontal drill and subsequent re-attempts due to poor subsurface geology such as large fracture zones or cobbles.
- Consequence: A horizontal directional drill would be abandoned for an alternative crossing methodology such as an open cut or bridge crossing. All construction costs would be sunk.
- Mitigation: Extensive investigation of the geological sub-surface is completed by geotechnical boreholes and geophysical surveying in order to select a drill path with an acceptable amount of risk. If the risk is determined to be too high or the measure to mitigate the risk too costly, another alternative may have to examined.

Risk #2 - Construction

- Risk: Upswing in activity in the oil & gas construction industry resulting in either contractor unavailability or drastically increased unit construction rates.

- Consequence: Construction cost premiums would be paid to secure competent labour resources.

- Mitigation: Based on present natural gas unit price projections and a general oversupply to North American markets, the likelihood of this risk is very small relative to the planned construction schedule of the project. A qualified Contractor will be selected by competitive bid. The tender documents for the HDD contracts will be attempted to be structured to arrive an appropriate balance between price and risk.

Risk #3 - Construction

- Risk: Drilling equipment or drill stem breakage resulting in a failed HDD drill.

- Consequence: Equipment breakdowns during drilling operations can result in having to abandon the planned drilling alignment and reattempt the drill with a new pilot hole if the original is compromised. This may severely impact the construction schedule as the original pilot hole may have to be 'swabbed' to remove drilling rods. Equipment breakdown during pullback of the installed line may result in loss of mud circulation and the pipe may become anchored in the in-situ soils.

- Mitigation: This is mitigated through a construction QA program that necessitates that all drilling rods meet applicable codes and standards for inspection and time-limited use. Maintenance records on all rig equipment will be reviewed by the construction inspection team prior to spudding of the drill.

Risk #4 - Construction

- Risk: Excessive surface water flow onto the jobsite and inundation of the right-of-way with mud.

- Consequence: Result would be an impact on both schedule and cost as the contractor would have to employ significant dewatering and water control measures to allow for the proper operation of equipment.

- Mitigation: Construction contracts are typically written so that this risk is borne by

the Contractor. Detailed design also accounts for predicted surface water flows reflected in construction grading and access plans.

Risk #5 - Construction

- Risk: Striking foreign utilities with the drill string.
- Consequence: Hitting a foreign underground utility poses a risk to life and property and may result in a drill path failure and third party remediation costs.
- Mitigation: A thorough review of land tenure is completed for the project area and an application for a ground disturbance is made to BC One-Call. During construction, a complete ground sweep is undertaken prior to any ground disturbance.

Risk #6 - Installation

- Risk: Drill contractor fails to complete the contracted work.
- Consequence: Incomplete, delayed or inappropriate installation, additional resources required to bring project to safe status or completion, potential liability to sub-contractors and other third party remediation costs, legal costs to recover losses.
- Mitigation: Thorough review of potential contractors prior to bidding, appropriate performance bonds required, thorough review of bids prior to contractor selection, effective inspection processes throughout installation.

Risk #7 - Installation

- Risk: Third party stalls or delays installation.
- Consequence: delayed installation, additional resources required to review and resolve third party claims, stand-by costs to contractor during delay period,
- Mitigation: Thorough review of potential stakeholders during project development, maintaining communication with known stakeholders, awareness of potential discontent, appropriate public consultation during project development and installation.

With respect to other potential Muskwa River crossing options already identified, the major risks can include:

Risk - Instream Installations requiring a Fisheries Act Authorization for Harmful Alteration, Disruption or Destruction (HADD) of Fish Habitat from the Department of Fisheries and Oceans (DFO)

- Risk: Fisheries Act Authorizations typically require habitat compensation to provide for no net loss of fish habitat which results in increased project costs

- Consequence: terms and conditions outlined in Fisheries Act Authorizations require documentation of functioning compensation habitat and long term monitoring which adds long term financial liabilities if fish habitat is deemed to be "not functioning" as intended. Monitoring may be required for up to 10 years post compensation habitat installation. Additional compensation habitat may be required over this period to offset compensation habitat that is "not functioning".

- Mitigation: Thorough review of potential project impacts, sound habitat compensation design to offset project impacts, well documented monitoring criteria in authorization, environmental monitoring during habitat construction, post-construction as-built survey of compensation habitat, long-term compensation monitoring by qualified environmental professional, review of compensation monitoring reports with DFO to identify issues over long term monitoring period, additional work to address issues over monitoring period

Risk – IP Bridge Ooption requiring permits from federal government. Note that this risk is not unique in that many projects would require additional provincial or federal government approval or permission.

- Risk: In order to attach the pipeline to a federally owned or managed bridge, permits or authorization from the federal government is required. A final determination on whether the federal government would grant such permit(s) has not been received.

- Consequence: IP Bridge Option may not be pursued.

- Mitigation: TGFN is communicating with the federal authorities and is examining the IP Bridge Option in more detail and working to resolve potential issues that may arise with federal government agencies.

Risk – IP Bridge Option – The seismic capacity of the bridge may not be sufficient for a pipeline attachment.

- Risk: The bridge may not be able to withstand a seismic event with an appropriate return period.

- Consequence: If the seismic event is severe enough then there is the possibility of damage to the pipeline resulting in either losing or curtailing gas supply to Fort Nelson.

- Mitigation: Evaluating the bridge for its seismic capacity. Designing the pipeline attachments for the seismic events predicted for the area.

As discussed in response to BCUC IR 1.9.2.4, the HDD Peak to Peak Option estimate is now greater than the $2.45 million included in the Application due to the discovery of surficial gravels. Therefore, other options are being actively explored. Regardless of which Option is ultimately chosen, TGFN will develop and follow the appropriate mitigation strategies to minimize the risk of cost overruns.

9.2.4 Have any factors become known by TGFN that would indicate costs for the project will be greater than $2.45 million?

Response:

Additional information is now known which indicates that costs for the HDD Peak to Peak Option would be higher than previously estimated. Geotechnical boreholes have been completed for the crossing and surficial gravels have been revealed to significant depths. This necessitates the use of wash-over casing at both the entry and exit of the HDD to allow the pilot hole to traverse the gravel layer without losing mud circulation. The lengths of the required wash-over casing are significant, and their installation would add significant cost to the drill. These additional costs will be included in the Class 3 Cost Estimate. As a result of this additional cost, TGFN is now considering other alternatives, especially the IP Bridge Option, in greater detail. The IP Bridge Option entails reducing the pipeline operating pressure to intermediate pressure (IP) and utilizing the existing highway bridge to cross the river. Currently, the IP Bridge Option is the Company's next preferred option, to avoid the risks and potential costs associated with any of the in stream crossing alternatives.

TGFN will file an evidentiary update including the preliminary Class 3 estimates for both the HDD Peak to Peak Option and the IP Bridge Option on November 19, 2010.

9.2.5 Please provide an estimated date that a class 3 cost estimate will become available to TGFN and the Commission.

Response:

Please see the response to BCUC IR 1.9.2.4. TGFN plans to file the Class 3 estimate on November 19, 2010.

9.2.6 Does TGFN believe that the Commission can accept TGFN's project under section 44.2 of the Utilities Commission Act before a class 3 cost estimate is available? If so, please explain.

Response:

The Commission always has the discretion to grant a section 44.2 approval without a Class 3 estimate.

The Commission's Guidelines for a Certificate of Public Convenience and Necessity application set out a general requirement for a Class 3 estimate to be provided for a selected, proposed project. Although the Guidelines do not state that they are applicable to section 44.2 capital expenditure applications, TGFN has taken the CPCN guidelines into account with respect to its section 44.2 application for the Muskwa Crossing project given its significance for the Fort Nelson Service Area. Due to the required timing of the Application and the in-service date of the Muskwa Crossing Project, it was not possible to include a class 3 estimate in the original Application. Instead, TGFN committed in the application to provide the class 3 estimate in an evidentiary update. We believe that this is consistent with the spirit of the Guidelines, which state:

[These guidelines] provide general guidance regarding the Commission's expectations of the information that should be included in CPCN applications while providing the flexibility for an application to reflect the specific circumstances of the applicant, the size and nature of the project, and the issues that it raises. An applicant is expected to apply the guidelines in a flexible and reasonable manner.

For the Muskwa River Crossing Project, a preliminary Class 3 estimate for the HDD Peak to Peak Option and the IP Bridge Option is being completed and will be filed on November 19, 2010, at which time the financial schedules and proposed rate impacts in the Application will be updated to reflect the revised cost estimate.

10.0 Reference: Structural Improvements

Exhibit B-1, Section 7.3.1, p. 32

10.1 How does the square footage of the new structures compare to those of the existing facilities?

Response:

The square footage of the new structure is 2,600. The new structure replaces two old structures which had a total square footage of approximately 2,800.

10.2 What additional features will the new facility offer over the old facilities?

Response:

As the old facilities were built over 40 years ago, they do not meet the current building requirements.

The new facility provides a number of benefits over the old facilities, including energy efficiency, environment and safety. The new facility is built according to BC Building code, using the climatic and seismic data for the Fort Nelson area. The new structure is fully insulated, having air and ply vapour barrier which helps in saving energy by reducing heating requirements. The new facility is provided with windows allowing natural light to penetrate the space and save electrical consumption. The metal sheet (both cladding and roof) are seamed instead of being screwed down ensuring a better insulation and to minimize the risk of leaking. The roof has an addition of an ice raking system to reduce dangerous snow and ice fall and improve personnel safety. The building has been provided with a washroom and oil separators as required by code.

11.0 Reference: Project Justification

Exhibit B-1, Section 7.3.2.2, p. 34

"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."

11.1 Has this inspection occurred yet? If so, what were its findings? If not, when will it occur?

Response:

TGFN's consultants completed a surface visual inspection of the Muskwa River pipeline crossing in mid-2010 and noted that there were no observable changes to the depth of cover within the floodplain or the bank erosion since the 2008 inspection. TGFN did consider additional in-stream inspection by a dive team but, after considering the expense, believe that the results of the previous inspections, including the recommendation to repair or replace the crossing as soon as practical, is sufficient.

12.0 Reference: Replacement Crossing

Exhibit B-1, Section 7.3.2.7.1, p. 36

"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."

12.1 When is BGC Engineering performing their investigation and when will these findings become available to TGFN and the Commission?

Response:

BGC Engineering conducted their geotechnical and geophysical investigations during the months of August, September, and October 2010. Their findings will be available on November 12, 2010. The design and risk assessment will be completed by November 19, 2010. As discussed in response to BCUC IR 1.9.2.4, TGFN will file an evidentiary update including the preliminary Class 3 estimates for both the HDD Peak to Peak Option and the IP Bridge Option on November 19, 2010.

12.2 What permits or right of ways would TGFN need to perform the HDD option? Explain what work TGFN has undertaken surrounding these items to date.

Response:

In the discussion below, TGFN describes the permits or rights of way that will be needed in order to construct the HDD Peak to Peak Option or the IP Bridge Option and the progress it has made with respect to those permits:

Ministry of Transportation and Infrastructure (MoTI)

The existing pipeline crossing lies in the road allowance of the Alaska Highway. The road allowance is owned and managed by the province while the structural components (i.e. bridge) are owned and managed by the federal government. The proposed HDD pipeline crossing will be in the same area as the existing pipeline albeit at a much greater depth. In most cases, using HDD to install a replacement pipeline within the same property does not require additional access rights such as a Right of Way. However, while the in-stream installation of 1974

appears to have been installed with permission from the province, the documentation of this agreement appears to be missing. Therefore, TGFN is currently communicating with the MoTI to develop a new agreement for the proposed pipeline crossing if the HDD Peak to Peak Option is pursued.

TGFN is also actively communicating with the MoTI with regard to the IP Bridge Option because under that option additional access rights from MoTI are required to install a pressure reducing station near the south side of the Muskwa River.

TGFN Property Services is maintaining an ongoing discussion with MoTI to complete the new agreement and, if the IP Bridge Option becomes the final preferred option, to negotiate an easement or right of way for the pressure reducing station.

Public Works and Government Services Canada (PWGSC)

TGFN has been in contact with PWGSC, which manages the bridge, to explore the possibility of using the Muskwa River highway bridge as a potentially viable alternative (the "IP Bridge Crossing" identified in section 7.3.2.7.4 of the Application). However, PWGSC has expressed a reluctance to allow a natural gas pipeline on the bridge. As a result, TGFN is working to resolve issues with PWGSC.

Federal Department of Fisheries and Oceans (DFO)

TGFN has reviewed the DFO (Pacific Region) Operation Statement for HDD installations and will comply with the operational statement during the HDD design, planning, and installation process. The actual notification to the DFO of the compliance to the Operational Statement will be completed prior to the commencement of construction. No further permit is required from the DFO for the HDD Peak to Peak Option.

TGFN has reviewed the DFO (Pacific Region) Operational Statement for Bridge Maintenance as this operational statement is most relevant to the task of installing a pipeline on a highway bridge crossing a watercourse. Should the IP Bridge Option be selected then TGFN will confirm and comply with this operational statement during the design, planning, and installation process. The actual notification to the DFO of the compliance to the operational statement will be completed prior to the commencement of construction. No further permit is required from the DFO for the IP Bridge Option.

Transport Canada – Navigable Waters Protection Act (NWPA)

For the HDD Peak to Peak Option and the IP Bridge Option, TGFN has reviewed the requirements of the NWPA and does not anticipate any issues with satisfying the requirements of the NWPA as there is no impediment to any river traffic at any time. Nonetheless, approval from Transport Canada is required for an HDD crossing. Communication with Transport Canada will be necessary following final selection of the crossing alternative to ensure NWPA requirements are met.

Pipeline Permit Application - BC Oil & Gas Commission (OGC)

To install the new gas pipeline and crossing, permission from the OGC is required and will be under the newly legislated Oil and Gas Activities Act (OGAA). However, TGFN is not yet at a stage to submit a Pipeline Permit Application. However, TGFN has initiated the activities described below in order to fulfill the OGC's requirements for the Pipeline Permit Application. Some of the activities may be beneficial in terms of moving the construction of a crossing forward if TGFN decides to pursue any of the other feasible alternatives.

1. **Environmental and Archaeological Assessments**

Environmental and archaeological assessments are required as part of the Pipeline Permit Application to the OGC. TGFN retained an environmental consultant to conduct an environmental assessment of the proposed crossing site and adjacent areas that may be impacted by the installation by any of the crossing options reviewed. An environmental risk assessment report of the various crossing options is being developed.

In addition, an archaeological assessment has been completed in the project area. Preliminary reporting indicates that the project area has been substantially disturbed by previous activities such as bridge construction, highway construction and logging. Final reports for both environmental and archaeological assessments are expected to be completed by mid-November. The results from the reports will form part of the requirements of the OGC application.

2. **Crown land**

In the preliminary HDD design, TGFN has identified that two small temporary workspaces on Crown land may be required during HDD installation. The OGC has the authority to authorize the occupation of the Crown land. TGFN will confirm its need for Crown land during the HDD design process and, as part of the Pipeline Permit Application, submit to the OGC for temporary use of the required Crown land. For the IP

Bridge Option, the objective is to utilize the road allowance and Crown land usage is not planned.

3. Public Consultation and Notification

The OGAA and the related Consultation and Notification Regulation requires gas companies, prior to application submission, to conduct an engagement process with potentially affected persons by notification or consultation. TGFN recognizes its responsibility and has initiated engagement with recognized stakeholders and potentially affected First Nations. Further communication with the potentially affected First Nations and other stakeholders will continue during the project planning stage.

12.3 What would be the expected useful life and amortization period of the HDD option if constructed?

Response:

The average service life of the proposed transmission pipe for the HDD Peak to Peak Option or the IP Bridge Option is approximately 60 years which is the same as the expected useful life of transmission pipe in general for Terasen Utilities. However, individual segments of a particular pipeline may have a longer or shorter useful life. The specific decision to replace segments is based on site and condition specific factors, assessed and determined from the ongoing asset integrity and asset management programs. TG Fort Nelson conducts numerous activities to ensure pipelines are fit for service which include corrosion monitoring, cathodic protection, leak surveys, pipeline patrol, class location surveys, public awareness, and damage prevention activities.

At the proposed depreciation rate of 1.63%, the depreciation period for TG Fort Nelson transmission mains is 61 1/3 years.

12.4 What is the projected rate impact for Rate Schedules 1, 2.1, 2.2 and 25 over the next 10 years if the project is i)completed on time and on budget or if ii) the project is completed on time but exceeds budget by 50%.

Response:

The following two tables show the capital Project costs, Rate Base, Income Tax, Cost of Service (Revenue Requirement), and Average Rate Impact for each of the two scenarios – completed on budget and exceeds budget by 50%.

The Rate impact for 2011 is relatively small under both scenarios because the project is only in Rate Base for the last 3 months of the year. The rate impact 'spikes' upward in 2012 because of the removal cost, $100,000, which has a one-time effect on rates due to the current regulatory treatment of negative salvage that has been approved for Terasen Gas Inc. ($100,000 / 595.2 TJ or 17 cents / GJ). For the years 2013 through 2020, for the scenario where the project is completed on time and on budget, the average rate impact is approximately $0.38 / GJ, while for the scenario where the capital costs are increased by 50% the average rate for the same time period is $0.56 / GJ (Line 62 of the 2 Tables).

TG FN- Cost of Service Impact From Muskwa Crossing Project

Line No.	Particulars	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Direct Additions	$ 2,350	$ 100								
2	AFUDC	125	7								
3	Retirements	(29)	-								
4	Total	$ 2,446	$ 107								
5											
6	Removal Costs		$ 100								
7	Property Taxes: General, School & Other		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
8											
9	Assumptions										
10	ROE	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
11	Equity	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
12	Return on Rate Base	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%
13	Tax Rate	26.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
14											
15	Depreciation Rates										
16	Mains	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%
17											
18	CCA Rates										
19	Mains (Class 49)	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
20											
21	Rate Base ($000s)										
22	Opening GPIS- Mains	$ -	$ 2,475	$ 2,582	$ 2,582	$ 2,582	$ 2,582	$ 2,582	$ 2,582	$ 2,582	$ 2,582
23	Additions- Mains	2,475	107	-	-	-	-	-	-	-	-
24	Retirements	(29)	-	-	-	-	-	-	-	-	-
25	Closing GPIS- Mains	2,475	2,582	2,582	2,582	2,582	2,582	2,582	2,582	2,582	2,582
26											
27	Opening Accumulated Depreciation- Capital	-	(7)	(48)	(90)	(132)	(174)	(216)	(258)	(300)	(343)
28	Depreciation Expense- Capital	(7)	(41)	(42)	(42)	(42)	(42)	(42)	(42)	(42)	(42)
29	Retirement	29	-	-	-	-	-	-	-	-	-
30	Closing Accumulated Depreciation- Capital	(7)	(48)	(90)	(132)	(174)	(216)	(258)	(300)	(343)	(385)
31	13 Month Adustment	(666)									
32	NPIS- Mid Year	$ 568	$ 2,501	$ 2,513	$ 2,471	$ 2,429	$ 2,387	$ 2,344	$ 2,302	$ 2,260	$ 2,218
33											
34	Income Tax Expense ($000s)										
35	Opening UCC- Capital	$ -	$ 2,256	$ 2,268	$ 2,086	$ 1,919	$ 1,766	$ 1,624	$ 1,494	$ 1,375	$ 1,265
36	Additions-Capital	2,350	200	-	-	-	-	-	-	-	-
37	CCA- Capital	(94)	(188)	(181)	(167)	(154)	(141)	(130)	(120)	(110)	(101)
38	Closing UCC- Capital	$ 2,256	$ 2,268	$ 2,086	$ 1,919	$ 1,766	$ 1,624	$ 1,494	$ 1,375	$ 1,265	$ 1,164
39											
40	Equity Return	$ 22	$ 95	$ 95	$ 94	$ 92	$ 91	$ 89	$ 87	$ 86	$ 84
41	Add: Depreciation Expense	7	41	42	42	42	42	42	42	42	42
42	Less: CCA	(94)	(188)	(181)	(167)	(154)	(141)	(130)	(120)	(110)	(101)
43	Add: Removal Costs	-	100	-	-	-	-	-	-	-	-
44	Taxable Income After Tax	$ (66)	$ 48	$ (44)	$ (31)	$ (19)	$ (8)	$ 1	$ 10	$ 18	$ 25
45											
46	Current Tax Rate	26.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
47	Taxable Income	$ (89)	$ 64	$ (58)	$ (41)	$ (26)	$ (11)	$ 2	$ 13	$ 24	$ 34
48											
49	Tax Expense	$ (24)	$ 16	$ (15)	$ (10)	$ (6)	$ (3)	$ 0	$ 3	$ 6	$ 8
50											
51	Cost of Service Impact ($000s)										
52	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
53	Depreciation Expense	7	41	42	42	42	42	42	42	42	42
54	Removal Costs	-	100	-	-	-	-	-	-	-	-
55	Property Tax	-	0	0	4	2	2	2	2	2	2
56	Earned Return	43	191	192	188	185	182	179	175	172	169
57	Income Tax Expense	(24)	16	(15)	(10)	(6)	(3)	0	3	6	8
58	**Revenue Requirement Impact ($000s)**	$ 26	$ 348	$ 219	$ 224	$ 223	$ 224	$ 224	$ 223	$ 223	$ 222
59											
60	Total Sales / T-Service Volumes (TJ)	598.1	597.3	596.4	595.2	595.5	595.5	595.5	595.5	595.5	595.5
61											
62	**Average Rate Impact $ / GJ**	**$ 0.044**	**$ 0.583**	**$ 0.368**	**$ 0.376**	**$ 0.375**	**$ 0.375**	**$ 0.375**	**$ 0.375**	**$ 0.374**	**$ 0.373**

TG FN- Cost of Service Impact From Muskwa Crossing Project
Project Capital Costs x 1.5

Line No.	Particulars	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Direct Additions	$ 3,525	$ 150								
2	AFUDC	188	10								
3	Retirements	(29)	-								
4	Total	$ 3,684	$ 160								
5											
6	Removal Costs		$ 100								
7	Property Taxes: General, School & Other		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
8											
9	Assumptions										
10	ROE	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
11	Equity	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
12	Return on Rate Base	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%	7.62%
13	Tax Rate	26.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
14											
15	Depreciation Rates										
16	Mains	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%	1.63%
17											
18	CCA Rates										
19	Mains (Class 49)	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
20											
21	Rate Base ($000s)										
22	Opening GPIS- Mains	$ -	$ 3,713	$ 3,873	$ 3,873	$ 3,873	$ 3,873	$ 3,873	$ 3,873	$ 3,873	$ 3,873
23	Additions- Mains	3,713	160	-	-	-	-	-	-	-	-
24	Retirements	(29)	-	-	-	-	-	-	-	-	-
25	Closing GPIS- Mains	3,713	3,873	3,873	3,873	3,873	3,873	3,873	3,873	3,873	3,873
26											
27	Opening Accumulated Depreciation- Capital	-	(10)	(72)	(135)	(198)	(261)	(324)	(388)	(451)	(514)
28	Depreciation Expense- Capital	(10)	(62)	(63)	(63)	(63)	(63)	(63)	(63)	(63)	(63)
29	Retirement	29	-	-	-	-	-	-	-	-	-
30	Closing Accumulated Depreciation- Capital	(10)	(72)	(135)	(198)	(261)	(324)	(388)	(451)	(514)	(577)
31	13 Month Adustment	(999)									
32	NPIS- Mid Year	$ 852	$ 3,752	$ 3,769	$ 3,706	$ 3,643	$ 3,580	$ 3,517	$ 3,454	$ 3,390	$ 3,327
33											
34	Income Tax Expense ($000s)										
35	Opening UCC- Capital	$ -	$ 3,384	$ 3,353	$ 3,085	$ 2,838	$ 2,611	$ 2,402	$ 2,210	$ 2,033	$ 1,871
36	Additions-Capital	3,525	250	-	-	-	-	-	-	-	-
37	CCA- Capital	(141)	(281)	(268)	(247)	(227)	(209)	(192)	(177)	(163)	(150)
38	Closing UCC- Capital	$ 3,384	$ 3,353	$ 3,085	$ 2,838	$ 2,611	$ 2,402	$ 2,210	$ 2,033	$ 1,871	$ 1,721
39											
40	Equity Return	$ 32	$ 143	$ 143	$ 141	$ 138	$ 136	$ 134	$ 131	$ 129	$ 126
41	Add: Depreciation Expense	10	62	63	63	63	63	63	63	63	63
42	Less: CCA	(141)	(281)	(268)	(247)	(227)	(209)	(192)	(177)	(163)	(150)
43	Add: Removal Costs	-	100	-	-	-	-	-	-	-	-
44	Taxable Income After Tax	$ (99)	$ 24	$ (62)	$ (43)	$ (25)	$ (10)	$ 5	$ 18	$ 29	$ 40
45											
46	Current Tax Rate	26.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
47	Taxable Income	$ (134)	$ 32	$ (83)	$ (57)	$ (34)	$ (13)	$ 6	$ 23	$ 39	$ 53
48											
49	Tax Expense	$ (36)	$ 8	$ (21)	$ (14)	$ (8)	$ (3)	$ 2	$ 6	$ 10	$ 13
50											
51	Cost of Service Impact ($000s)										
52	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
53	Depreciation Expense	10	62	63	63	63	63	63	63	63	63
54	Removal Costs	-	100	-	-	-	-	-	-	-	-
55	Property Tax	-	0	1	5	4	4	4	4	4	4
56	Earned Return	65	286	287	282	278	273	268	263	258	254
57	Income Tax Expense	(36)	8	(21)	(14)	(8)	(3)	2	6	10	13
58	**Revenue Requirement Impact ($000s)**	$ 40	$ 456	$ 330	$ 336	$ 336	$ 336	$ 336	$ 336	$ 335	$ 334
59											
60	Total Sales / T-Service Volumes (TJ)	598.1	595.2	594.3	593.1	593.3	593.3	593.3	593.3	593.3	593.3
61											
62	**Average Rate Impact $ / GJ**	**$ 0.066**	**$ 0.766**	**$ 0.556**	**$ 0.567**	**$ 0.566**	**$ 0.567**	**$ 0.567**	**$ 0.566**	**$ 0.564**	**$ 0.562**

12.5 If the proposed HDD crossing goes ahead, how will the change impact operating and maintenance costs?

Response:

TG Fort Nelson expects that either the HDD Peak to Peak Option or the IP Bridge Option would result in marginal O&M savings as a result of lower inspection costs. There is a higher risk of pipeline cover loss with an open cut installation, compared to the others. This results in more frequent inspections required to determine the condition of the pipeline cover with the open cut installations.

12.6 How will the transportation capacity of the proposed HDD 168.3mm crossing compare to the capacity of the existing line 114mm?

Response:

The following discussion is intended to provide a response to BCUC IR 1.12.6 through 1.12.10.

As noted in Section 7.3.2.1 of the 2011 TGFN Revenue Requirements Application, the original crossing of the Muskwa River was completed in 1960 during the original pipeline construction by installing a 114 mm diameter (NPS 4) pipe on the existing highway bridge. In 1973, the bridge was due to be replaced and the then pipeline operators decided to install a replacement 168 mm diameter (NPS 6) pipeline with an in-stream installation immediately upstream of the new bridge location using the open cut method. At the time of this replacement installation, it was not uncommon to "oversize" crossings to allow for future load growth because of the relatively high cost of river crossing installations.

At the time of filing of this Application, TGFN chose to maintain the size of the crossing at 168 mm because there was no initial apparent reason to depart from the existing pipe size.

However, as engineering work progressed, TGFN decided to re-examine the pipeline capacity and costs to determine if the existing pipe size (168mm) was valid. The time frame used for this re-examination was 60 years, the assumed life of the new crossing,

The results of this re-examination are summarized below:

- With a 114 mm crossing, the system will be at approximately 100% capacity in 2070/71;
- With a 168 mm crossing, the system will be at approximately 97% capacity in 2070/71; and

- A change from a 168 mm crossing to a 114 mm crossing will provide an estimated cost savings of $78,000.

In light of the above information, TGFN is recommending that, should the proposed HDD Peak to Peak Option remain the most cost effective, the crossing size be reduced from 168 mm to 114 mm for.

Please note that the above analysis is based on the current 20 year load forecast and a linear extrapolation of this forecast from year 20 to year 60. A significant load addition, though not currently anticipated, could require a reinforcement of the system prior to 2070/71. However, TGFN is of the opinion that the most likely location of a future significant load increase would be upstream of the crossing because the load downstream of the crossing is primarily residential and commercial. Also, should system reinforcement be required, it would most likely be in the form of looping starting at the beginning or upstream end of the Fort Nelson lateral and not necessarily require a second crossing of the Muskwa River.

As discussed in the response to BCUC IR 1.9.2.4, TGFN is examining other alternatives, including the IP Bridge Option, in more detail.

12.7 Does the proposed HDD crossing provide sufficient capacity for expected growth in the region or will it be operating near capacity when installed?

Response:

Please refer to the response to BCUC IR 1.12.6.

12.8 Based on current forecast of customer growth and usage rates, in what future year would TGFN be at maximum capacity on the proposed HDD crossing?

Response:

Please see the response to BCUC IR 1.12.6.

12.9 If the existing pipeline connecting into the crossing remains at 114m, what is the point of installing a 168.3 mm crossing?

Response:

Please see the response to BCUC IR 1.12.6.

12.10 What is the incremental cost difference between installing an HDD crossing that is of equal size to the existing pipeline vs installing a HDD crossing of 168.3mm?

Response:

Please see the response to BCUC IR 1.12.6.

13.0 Reference: Replacement Crossing

Exhibit B-1, table 7-3, p. 38

13.1 Please confirm that other than live line lowering, cabled concrete mats or rip rat replacement, no other form of covering or encasing the existing pipeline is possible to salvage the existing structure by means of an in stream remediation.

Response:

TGFN retained Chinook Engineering, an experienced Canadian pipeline engineering consulting company, to advise TGFN of the reasonable methods of repairing or replacing the pipeline crossing. TGFN has relied upon Chinook to provide TGFN with appropriate and accurate information in order for TGFN to evaluate and select a cost-effective and secure pipeline crossing alternative. The in stream methods described by Chinook are all possible, although with varying levels of uncertainties and risks. TGFN is not currently aware of other alternatives that would represent a cost effective long term solution to the concerns at this river crossing.

14.0 Reference: Preliminary Cost Estimate and Spending Profile

Exhibit B-1, Table 7-4, p. 38

14.1 To date, how much has TGFN spent on Project development and alternative evaluation costs?

Response:

As of Oct 25, 2010 Terasen Gas has spent approximately $126,000 on project development and alternative evaluation costs, as detailed below.

Agency	25-Oct 2010	Total	Scope
Chinook	3.1	15	Engineering
BGC	34.5	135	Geotechnical
EDI	26.4	32	Environmental/Arch
Can Am	27.8	28	Site survey
CWMM		12	Bridge crossing
B&T	10.8	11	Aerial Crossing Cl3
Entec	2.1	12	HDD Design & Risk Ass
	104.7	245	Total
PMO	21.1	30	Project Management
Engineering		10	Terasen Engineering
Miscellaneous		15	
	125.8	300	Total

Total project development and alternative evaluation costs are still estimated to be $300,000 with the largest portion being the geotechnical and geophysical exploration (45%).

Note that the majority of these costs are incurred to reach a final determination of the preferred option, and some costs are common to all alternatives (i.e. site survey, environmental and archaeological).

14.2 What percentage of total project costs does TGFN believe is reasonable for project development and evaluation and what has been the percentage of these costs to total project costs for TGFN on the last 2 largest capital projects.

Response:

The reasonableness of a project's development and evaluation costs cannot be determined by simply expressing them as a percentage of overall project costs. Instead, the specific circumstances surrounding a project must be considered. Project development and evaluation costs are dependent on the nature and complexity of a project. As a project increases in complexity, more assessment work will be required to evaluate the options available, leading to higher evaluation costs.

For the proposed Muskwa River project, the pipeline crossing is critical to the delivery of natural gas to the community of Fort Nelson. With the factors that have to be considered and the alternatives available, TG Fort Nelson believes the $300,000 estimated for project development and alternative evaluation costs is reasonable and required. As indicated, the reasonableness of the Muskwa River crossing project development and evaluation costs cannot be determined by simply expressing them as a percentage of overall project costs and instead the specific circumstances surrounding the pipeline must be considered.

Over the last five years, the two largest capital projects for TG Fort Nelson as determined by total project costs are the Odorizer Replacement project (replacement odorizer with a pair of double-walled underground tanks essentially completed in 2006 at an approximate cost of $300,000) and the Upgrade of the Odorizer Station (installation of pressure control valves and overpressure protection devices to reduce pressure from the Spectra system completed in 2009 at an approximate cost of $230,000). There were no incremental development and evaluation costs incurred as the projects were well defined in scope and requirements.

14.3 Please update this table based on most current information available.

Response:

At this time, TGFN has been advised that the preliminary results of the geotechnical investigation indicate subsurface gravels will substantially affect the cost estimate of the HDD Peak to Peak Option. As part of the evidentiary update to be filed on November 19, 2010, TGFN will update Table 7-4.

15.0 Reference: Other Work Required

Exhibit B-1, Section 7.3.2.11, p. 39

15.1 Please provide a status update on the outstanding items listed in this section.

Response:

The following table lists the items noted in Sec 7.3.2.11 and the status of each item.

Item	Target Date	Status
Environmental & archaeological reviews of the crossing site.	mid November 2010	Final review
Topographical survey of crossing site	Sep 1 2010	Completed
Aerial crossing conceptual design and cost estimate	Aug 27 2010	Completed
First Nations discussion initiated	Initiated	On going
Environmental Impact and Permit Assessment of in-stream alternatives	mid November 2010	Final review
Assessment of the feasibility of installing a pipeline on the Muskwa River bridge	mid November 2010	Final review
Further discussion with PWGSC for permission to attach pipeline on bridge	Initiated	On going
Assessment of lowering pipeline pressure on future Ft Nelson system reinforcement plans	Nov 8 2010	Completed

15.2 Based on any of the procedures occurring since submitting this Application, have plans for this pipeline crossing, including construction timelines, been modified from those included in this application? If so, please explain.

Response:

TGFN is aware that extensive gravels noted in preliminary borehole analysis will increase the cost estimate of the HDD Peak to Peak Option. As a result, and as indicated in response to BCUC IR 1.9.2.4, TGFN is now exploring other options, especially the IP Bridge Option, in greater detail. TGFN will file an evidentiary update including the preliminary Class 3 estimates for both the HDD Peak to Peak Option and the IP Bridge Option on November 19, 2010. Regardless of the final option chosen, TGFN remains confident that the Project will be complete by late fall 2011.

15.3 Please provide a timeline for when each of these items will be complete in order to meet timelines for construction?

Response:

Please see the target date for these items listed in the response to BCUC IR1.15.1.

15.4 When does TGFN expect to select an alternative for the project?

Response:

Final selection of the pipeline crossing methodology will be made following completion of the various studies and class 3 estimates currently underway. Much of this information will be ready by November 19, 2010; however, there may still be outstanding issues to consider on that date or the studies may reveal information that warrants further evaluation. Please also see the response to BCUC IR 1.9.2.4.

16.0 Reference: Impact of Depreciation on Rate Base

Exhibit B-1, Table 7-6, p. 45

16.1 Please confirm that the recommended depreciation rates exclude negative salvage values.

Response:

TG Fort Nelson confirms that the recommended depreciation rates exclude negative salvage values, and are consistent with the rates approved in the TGI 2010-2011 Revenue Requirement Negotiated Settlement Agreement.

16.2 This table attempts to quantify the rate change by comparing depreciation rates as applied to the 2010 opening balances of asset accounts.

16.2.1 For the purposes of this calculation, why did TGI use opening balances instead of mid-year balances for these calculation given the depreciation methods adopted by TGI.

Response:

TG Fort Nelson proposed in its 2009 Application, dated October 8, 2009, to capture the effect of the difference in depreciation rates in the IFRS Transitional Deferral Account. The BCUC in its Order No. G-147-09, Item 2, dated December 3, 2009, approved this proposal. TG Fort Nelson interpreted this as permission to defer the difference in depreciation rates, but not as permission to defer the difference in the timing of depreciation commencement. The request to commence depreciation in the month following the available-for-use date for regulatory purposes has been included as part of this Application in Section 10.1 which is consistent with the approved treatment from the Commission for the other Terasen Gas utilities.

17.0 Reference: RSAM Deferral Account

Exhibit B-1, Section 9, Schedule 4.1

17.1 Please explain how the $101 thousand adjustment in column 6 compares to the $59 thousand increase in table 7-6 on page 45.

Response:

The $101 thousand adjustment in column 6 of Exhibit B-1, Section 9, Schedule 4.1 has no relation to the $59 thousand increase in Table 7-6 on page 45. The $101 thousand is an adjustment to Accumulated Depreciation only and does not affect the 2010 opening balance of Gas Plant in Service upon which the depreciation expense in Table 7-6 is calculated. The incremental depreciation expense resulting from the depreciation rate changes for 2010 as shown in Table 7-6 is instead included in Column 7 of Schedule 4.1.

18.0 Reference: Contributions in Aid of Construction

Exhibit B-1, Section 9, Schedule 5.0

18.1 Please explain the "other" addition in column 3, which was made in 2009.

Response:

The "other" addition in column 3 mainly refers to a $60 thousand contribution from BC Hydro to relocate a lateral out of the BC Hydro power plant property at their request. The remaining $32 thousand consists of other miscellaneous contributions from customers.

19.0 Reference: RSAM Deferral Account

Exhibit B-1, Section 9, Schedule 6.0

19.1 Please provide the supporting calculation for the $101 taxes deducted on the $165 additions and explain why this tax amount is so high relative to the additions.

Response:

The amount of taxes deducted is calculated as follows, using the 2009 tax rate:

Gross Additions - Column 4:	($165)
Add: Amortization Other / Int. – Column 8:	($170)
Sub-total	($335)
Multiply: (2009 Tax Rate):	(30%)
Total taxes	$101

20.0 Reference: RSAM Deferral Account

Exhibit B-1, Section 9, Schedule 14.0

20.1 Please explain what the $71 thousand dollars of 2011 Amortization expense relates to and how this amount was calculated.

Response:

The deferral accounts that relate to the amortization expense of $71 thousand can be found in Section 9, Schedule 6.1, Lines 13 to 23, Column 7. The three specific accounts that sum up to the $71 thousand amortization expense are:

1. Deferred Interest (credit of $6 thousand) approved by the Commission in Order No. G-147-09. Consistent with past practice, the Deferred Interest is being amortized in the following year.

2. ROE & Capital Structure ($56 thousand), approved by the Commission in Order No. G-147-09. TG Fort Nelson is proposing to have the projected balance from 2010 amortized in 2011 (see Section 7.6.6 for details).

3. Revenue Requirement Application ($21 thousand). TG Fort Nelson is forecasting the costs for this Revenue Requirement Application will be approximately $21 thousand. TG Fort Nelson is proposing to amortize these costs in 2011 (see Section 7.6.5 for details).

The amounts amortized are the projected opening balances for 2011.

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21.0 Reference: Appendix A

Exhibit B-1

21.1 Please provide, in confidence, the complete Appendices A-F of the document included in Appendix A of the Application.

Response:

The completed Appendices A-F were inadvertently omitted from the Application, and are not required to be filed in confidence. Please refer to Attachment 21.1 (A to F) for the omitted appendices.

Index of Attachment 21.1 is as follows:

- Appendix A – Muskwa River Hydrology and Existing Pipeline Crossing
- Appendix B – Option 1 – Front End Engineering and Design – HDD Installation
- Appendix C – Option 2 – Front End Engineering and Design – Open Cut Crossing
- Appendix D – Option 3 – Front End Engineering and Design – Live Line Lowering
- Appendix E – Option 4 – Front End Engineering and Design – Bridge Crossing and Station
- Appendix F – Option Comparison and Evaluation

22.0 Reference: Appendix B

Exhibit B-1

22.1 Please provide, in confidence, the complete Appendices A-D of the document included in Appendix B of the Application.

Response:

The completed Appendices A-D were inadvertently omitted from the Application, and are not required to be filed in confidence. Please refer to Attachment 22.1 (A-D) for the omitted appendices.

Index of Attachment 22.1 is as follows:

- Appendix A – Cost Estimate Summary – D50:300 Rip Rap
- Appendix B – Cost Estimate Summary – Cabled Concrete Mats
- Appendix C – Construction Plan
- Appendix D – Project FEED Option Cost Comparisons

Attachment 1.2

Approximate Customer Billing Summary
Terasen Gas Inc.- Fort Nelson Service Area

Fort Nelson Rate Schedule 1		Use Rate for Annual Bill				2009					2010					2011				
		TG FN		TGI		TG FN		TGI			TG FN		TGI			TG FN		TGI[4]		
Line	Particulars	Volume	Unit	Volume	Unit	Rate	Annual ($)	Rate	Annual ($)	TGFN Less Than /(Greater Than) TGI	Rate	Annual ($)	Rate	Annual ($)	TGFN Less Than /(Greater Than) TGI	Rate	Annual ($)	Rate	Annual ($)	TGFN Less Than /(Greater Than) TGI
1	Annual Use (GJ)	140		140																
2	Annual Use Embedded in Basic Charge (GJ)	24		-																
3	Net Annual Use for Volumetric Charges (GJ)	116		140																
4																				
5	TG FN Minimum Monthly Charge/ TGI Monthly Basic Charge [1]	12	mnths	12	mnths	20.97	252	11.88	143	(109)	19.90	239	11.84	142	(97)	21.08	253	11.84	142	(111)
6	Bundled Volumetric Rate[1] ($/GJ)	116	GJ			8.6213	1,000				8.0835	938				8.2010	951			
7																				
8	Unbundled Volumetric Rate ($/GJ)																			
9	Commodity Cost Recovery Charge[1] ($/GJ)	116	GJ	140	GJ	6.3853	741	6.1033	854	114	6.0465	701	5.1285	718	17	5.7840	671	4.9760	697	26
10	Midstream Cost Recovery Charge ($/GJ)	116	GJ	140	GJ	-	-	0.9030	126	126	-	-	1.6210	227	227	-	-	1.6210	227	227
11	Cost of Gas Volumetric Charges ($/GJ)					6.3853	741	7.0063	981	240	6.0465	701	6.7495	945	244	5.7840	671	6.5970	924	253
12																				
13	Volumetric Delivery Rate[1] ($/GJ)	116	GJ	140	GJ	2.0000	232	2.9610	415	183	2.0000	232	3.1790	445	213	2.3840	277	3.2750	459	182
14	RSAM Rate Rider ($/GJ)	116	GJ	140	GJ	0.2360	27	0.0010	0	(27)	0.0370	4	(0.0530)	(7)	(12)	0.0330	4	(0.0520)	(7)	(11)
15	Delivery Volumetric Charges ($/GJ)					2.2360	259	2.9620	415	155	2.0370	236	3.1260	438	201	2.4170	280	3.2230	451	171
16																				
17	Approximate Total Annual Bill ($)						1,252		1,538	286		1,176		1,525	348		1,204		1,517	313
18	Approximate Annual Bill ($)- Delivery[3]						358		557	**199**		330		580	**250**		394		593	**199**

Notes:

1 2009 and 2010 rates reflect the weighted average for the year based on the number of months each approved rate was applicable

2 The approximate delivery portion of the annual bill for TG FN rates excludes the cost of gas component (24 GJ x Commodity Rate) from the Minimum Monthly Charge

3 2011 Commodity and Midstream Recovery charges reflect the currently approved rates and are subject to change

4 Other than the RSAM Rate Rider, all other TGI rate riders have been excluded

5 TGI Rates reflect Inland Residential Rates (Rate Schedule 1)

Approximate Customer Billing Summary
Terasen Gas Inc.- Fort Nelson Service Area

Fort Nelson Rate Schedule 2.1		Use Rate for Annual Bill				2009					2010					2011				
		TG FN		TGI		TG FN		TGI			TG FN		TGI			TG FN		TGI[4]		
Line	Particulars	Volume	Unit	Volume	Unit	Rate	Annual ($)	Rate	Annual ($)	TGFN Less Than /(Greater Than) TGI	Rate	Annual ($)	Rate	Annual ($)	TGFN Less Than /(Greater Than) TGI	Rate	Annual ($)	Rate	Annual ($)	TGFN Less Than /(Greater Than) TGI
1	Annual Use (GJ)	460		460																
2	Annual Use Embedded in Basic Charge (GJ)	24		-																
3	Net Annual Use for Volumetric Charges (GJ)	436		460																
4																				
5	TG FN Minimum Monthly Charge/ TGI Monthly Basic Charge [1]	12	mnths	12	mnths	36.01	432	24.92	299	(133)	34.94	419	24.84	298	(121)	39.28	471	24.84	298	(173)
6	Bundled Volumetric Rate[1] ($/GJ)	436	GJ			8.8533	3,860				8.3155	3,626				8.4970	3,705			
7																				
8	Unbundled Volumetric Rate ($/GJ)																			
9	Commodity Cost Recovery Charge[1] ($/GJ)	436	GJ	460	GJ	6.3853	2,784	6.1033	2,808	24	6.0465	2,636	5.1285	2,359	(277)	5.7840	2,522	4.9760	2,289	(233)
10	Midstream Cost Recovery Charge ($/GJ)	436	GJ	460	GJ	-	-	0.9070	417	417	-	-	1.6150	743	743	-	-	1.6150	743	743
11	Cost of Gas Volumetric Charges ($/GJ)					6.3853	2,784	7.0103	3,225	441	6.0465	2,636	6.7435	3,102	466	5.7840	2,522	6.5910	3,032	510
12																				
13	Volumetric Delivery Rate[1] ($/GJ)	436	GJ	460	GJ	2.2320	973	2.4790	1,140	167	2.2320	973	2.6430	1,216	243	2.6800	1,168	2.7140	1,248	80
14	RSAM Rate Rider ($/GJ)	436	GJ	460	GJ	0.2360	103	0.0010	0	(102)	0.0370	16	(0.0530)	(24)	(41)	0.0330	14	(0.0520)	(24)	(38)
15	Delivery Volumetric Charges ($/GJ)					2.4680	1,076	2.4800	1,141	65	2.2690	989	2.5900	1,191	202	2.7130	1,183	2.6620	1,225	42
16																				
17	Approximate Total Annual Bill ($)						4,292		4,665	372		4,045		4,591	547		4,176		4,554	378
18	Approximate Annual Bill ($)- Delivery[3]						1,355		1,440	**85**		1,263		1,489	**226**		1,515		1,523	**7**

Notes:

1 2009 and 2010 rates reflect the weighted average for the year based on the number of months each approved rate was applicable

2 The approximate delivery portion of the annual bill for TG FN rates excludes the cost of gas component (24 GJ x Commodity Rate) from the Minimum Monthly Charge

3 2011 Commodity and Midstream Recovery charges reflect the currently approved rates and are subject to change

4 Other than the RSAM Rate Rider, all other TGI rate riders have been excluded

5 TGI Rates reflect Inland Rate Schedule 2

Approximate Customer Billing Summary
Terasen Gas Inc.- Fort Nelson Service Area

Fort Nelson Rate Schedule 2.2

Line	Particulars	Use Rate for Annual Bill TG FN Volume	Unit	TGI Volume	Unit	2009 TG FN Rate	2009 TG FN Annual ($)	2009 TGI Rate	2009 TGI Annual ($)	2009 TGFN Less Than /(Greater Than) TGI	2010 TG FN Rate	2010 TG FN Annual ($)	2010 TGI Rate	2010 TGI Annual ($)	2010 TGFN Less Than /(Greater Than) TGI	2011 TG FN Rate	2011 TG FN Annual ($)	2011 TGI[4] Rate	2011 TGI[4] Annual ($)	2011 TGFN Less Than /(Greater Than) TGI
1	Annual Use (GJ)	3,100		3,100																
2	Annual Use Embedded in Basic Charge (GJ)	24		-																
3	Net Annual Use for Volumetric Charges (GJ)	3,076		3,100																
4																				
5	TG FN Minimum Monthly Charge/ TGI Monthly Basic Charge [1]	12	mnths	12	mnths	36.01	432	24.92	299	(133)	34.94	419	24.84	298	(121)	39.28	471	24.84	298	(173)
6	Bundled Volumetric Rate[1] ($/GJ)	3,076	GJ			8.8533	27,233				8.3155	25,578				8.4970	26,137			
7																				
8	Unbundled Volumetric Rate ($/GJ)																			
9	Commodity Cost Recovery Charge[1] ($/GJ)	3,076	GJ	3,100	GJ	6.3853	19,641	6.1033	18,920	(721)	6.0465	18,599	5.1285	15,898	(2,701)	5.7840	17,792	4.9760	15,426	(2,366)
10	Midstream Cost Recovery Charge ($/GJ)	3,076	GJ	3,100	GJ	-	-	0.9070	2,812	2,812	-	-	1.6150	5,007	5,007	-	-	1.6150	5,007	5,007
11	Cost of Gas Volumetric Charges ($/GJ)					6.3853	19,641	7.0103	21,732	2,091	6.0465	18,599	6.7435	20,905	2,306	5.7840	17,792	6.5910	20,432	2,641
12																				
13	Volumetric Delivery Rate[1] ($/GJ)	3,076	GJ	3,100	GJ	2.2320	6,866	2.4790	7,685	819	2.2320	6,866	2.6430	8,193	1,328	2.6800	8,244	2.7140	8,413	170
14	RSAM Rate Rider ($/GJ)	3,076	GJ	3,100	GJ	0.2360	726	0.0010	3	(723)	0.0370	114	(0.0530)	(164)	(278)	0.0330	102	(0.0520)	(161)	(263)
15	Delivery Volumetric Charges ($/GJ)					2.4680	7,592	2.4800	7,688	96	2.2690	6,979	2.5900	8,029	1,050	2.7130	8,345	2.6620	8,252	(93)
16																				
17	Approximate Total Annual Bill ($)						27,665		29,719	2,054		25,998		29,232	3,234		26,608		28,982	2,374
18	Approximate Annual Bill ($)- Delivery[3]						7,870		7,987	**117**		7,254		8,327	**1,074**		8,678		8,550	**(127)**

Notes:

1 2009 and 2010 rates reflect the weighted average for the year based on the number of months each approved rate was applicable

2 The approximate delivery portion of the annual bill for TG FN rates excludes the cost of gas component (24 GJ x Commodity Rate) from the Minimum Monthly Charge

3 2011 Commodity and Midstream Recovery charges reflect the currently approved rates and are subject to change

4 Other than the RSAM Rate Rider, all other TGI rate riders have been excluded

5 TGI Rates reflect Inland Rate Schedule 2

Approximate Customer Billing Summary
Terasen Gas Inc.- Fort Nelson Service Area

Fort Nelson Rate Schedule 25		Use Rate for Annual Bill				2009					2010					2011				
		TG FN		TGI		TG FN		TGI			TG FN		TGI			TG FN		TGI		
Line	Particulars	Volume	Unit	Volume[2]	Unit	Rate	Annual ($)	Rate	Annual ($)	TGFN Less Than /(Greater Than) TGI	Rate	Annual ($)	Rate	Annual ($)	TGFN Less Than /(Greater Than) TGI	Rate	Annual ($)	Rate	Annual ($)	TGFN Less Than /(Greater Than) TGI
1	Annual Use (GJ)	24,775		24,775																
2																				
3	TGI Monthly Basic Charge	12	mnths	12	mnths			588.75	7,065	7,065			587.00	7,044	7,044			587.00	7,044	7,044
4	Monthly Administration Charge	12	mnths	12	mnths	202.00	2,424	78.25	939	(1,485)	202.00	2,424	78.00	936	(1,488)	202.00	2,424	78.00	936	(1,488)
5	Monthly Demand Charge			130	GJ			14.70	22,888	22,888			15.55	24,218	24,218			15.94	24,823	24,823
6																				
7	Volumetric Rate[1] ($/GJ)			24,775	GJ			0.4400	10,901	10,901			0.6290	15,583	15,583			0.6450	15,980	15,980
8	i) First 20 Gigajoules	240	GJ	-		2.3190	557		-	(557)	2.3190	557		-	(557)	2.8727	689		-	(689)
9	ii) Next 260 Gigajoules	3,120	GJ	-		2.1450	6,692		-	(6,692)	2.1450	6,692		-	(6,692)	2.6559	8,286		-	(8,286)
10	iii) Excess over 280 Gigajoules	21,415	GJ	-		1.7360	37,176		-	(37,176)	1.7360	37,176		-	(37,176)	2.1462	45,961		-	(45,961)
11							44,425		10,901	(33,524)		44,425		15,583	(28,842)		54,937		15,980	(38,957)
12	RSAM Rate Rider ($/GJ)	24,775		24,775	GJ	0.2360	5,847	-	-	(5,847)	0.0370	917	-	-	(917)	0.0330	818	-	-	(818)
13	Delivery Volumetric Charges ($/GJ)					2.0292	50,272	0.4400	10,901	(39,371)	1.8302	45,342	0.6290	15,583	(29,759)	2.2504	55,755	0.6450	15,980	(39,775)
14																				
15	Approximate Total Annual Bill ($)						52,696		18,905	(33,791)		47,766		23,563	(24,203)		58,179		23,960	(34,219)

Notes:

1 2009 and 2010 rates reflect the weighted average for the year based on the number of months each approved rate was applicable

2 Demand volume assumes the TGI Inland Rate 25 ratio of monthly demand compared to annual use as shown on TGI Inland Rate 25 annual bill calculations and does not represent a specific customer

3 Other than the RSAM Rate Rider, all other TGI rate riders have been excluded (RSAM Rate Rider does not apply to TGI Rate 25 customers)

4 TGI Rates reflect Inland Rate Schedule 25

Table 2-2 *(Revised)*: Proposed Tariff Rate Change & 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	$ 19.370	$ -	$ (0.070)	$ (11.570)	$ 7.730	$ 1.718	$ 11.570	$ 0.066	$ 21.084
2nd Blk Next 28 GJ $ / GJ	$ 7.821	$ -	$ (0.037)	$ (5.784)	$ 2.000	$ 0.384	$ 5.784	$ 0.033	$ 8.201
3rd Blk Excess of 30 GJ $ / GJ	$ 7.763	$ -	$ (0.037)	$ (5.784)	$ 1.942	$ 0.373	$ 5.784	$ 0.033	$ 8.132
General Service - Small Commercial									
1st Blk ≤ 2 GJ $ / Month	$ 34.410	$ -	$ (0.070)	$ (11.570)	$ 22.770	$ 4.881	$ 11.570	$ 0.066	$ 39.287
2nd Blk Next 298 GJ $ / GJ	$ 8.053	$ -	$ (0.037)	$ (5.784)	$ 2.232	$ 0.448	$ 5.784	$ 0.033	$ 8.497
3rd Blk Excess of 300 GJ $ / GJ	$ 7.982	$ -	$ (0.037)	$ (5.784)	$ 2.161	$ 0.434	$ 5.784	$ 0.033	$ 8.412
General Service - Large Commercial									
1st Blk ≤ 2 GJ $ / Month	$ 34.410	$ -	$ (0.070)	$ (11.570)	$ 22.770	$ 4.881	$ 11.570	$ 0.066	$ 39.287
2nd Blk Next 298 GJ $ / GJ	$ 8.053	$ -	$ (0.037)	$ (5.784)	$ 2.232	$ 0.448	$ 5.784	$ 0.033	$ 8.497
3rd Blk Excess of 300 GJ $ / GJ	$ 7.982	$ -	$ (0.037)	$ (5.784)	$ 2.161	$ 0.434	$ 5.784	$ 0.033	$ 8.412
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	$ 297.00			$ 1,755.00
Administration Charge	$ 202.00	$ -	$ -		$ 202.00	$ -			$ 202.00
RSAM Recovery Charge	$ 0.037	$ -	$ (0.037)	$ -	$ -		$ -	$ 0.033	$ 0.033

Table 2-3 *(Revised)*: 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
					20.4%			
Rate Class 2.3 - Natural Gas Vehicle Fuel Service								
1st Blk ≤ 2 GJ $ / Month	$ 33.99	$ -	$ (11.57)	$ 22.42	$ 4.57	$ 11.57	$ -	$ 38.56
2nd Blk Next 298 GJ $ / GJ	$ 8.539	$ -	$ (5.784)	$ 2.755	$ 0.561	$ 5.784	$ -	$ 9.100
3rd Blk Excess of 300 GJ $ / GJ	$ 8.469	$ -	$ (5.784)	$ 2.685	$ 0.547	$ 5.784	$ -	$ 9.016
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	$ 297.00			$ 1,755.00
Gas Cost Recovery Charge	$ 5.784		$ (5.784)	$ -	$ -	$ 5.784		$ 5.784
RSAM Rate Rider	$ 0.037	$ (0.037)		$ -	$ -	$ -	$ 0.033	$ 0.033
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	$ 297.00			$ 1,755.00
Gas Cost Recovery Charge	$ 5.784		$ (5.784)	$ -		$ 5.784		$ 5.784
RSAM Rate Rider	$ 0.037	$ (0.037)		$ -		$ -	$ 0.033	$ 0.033

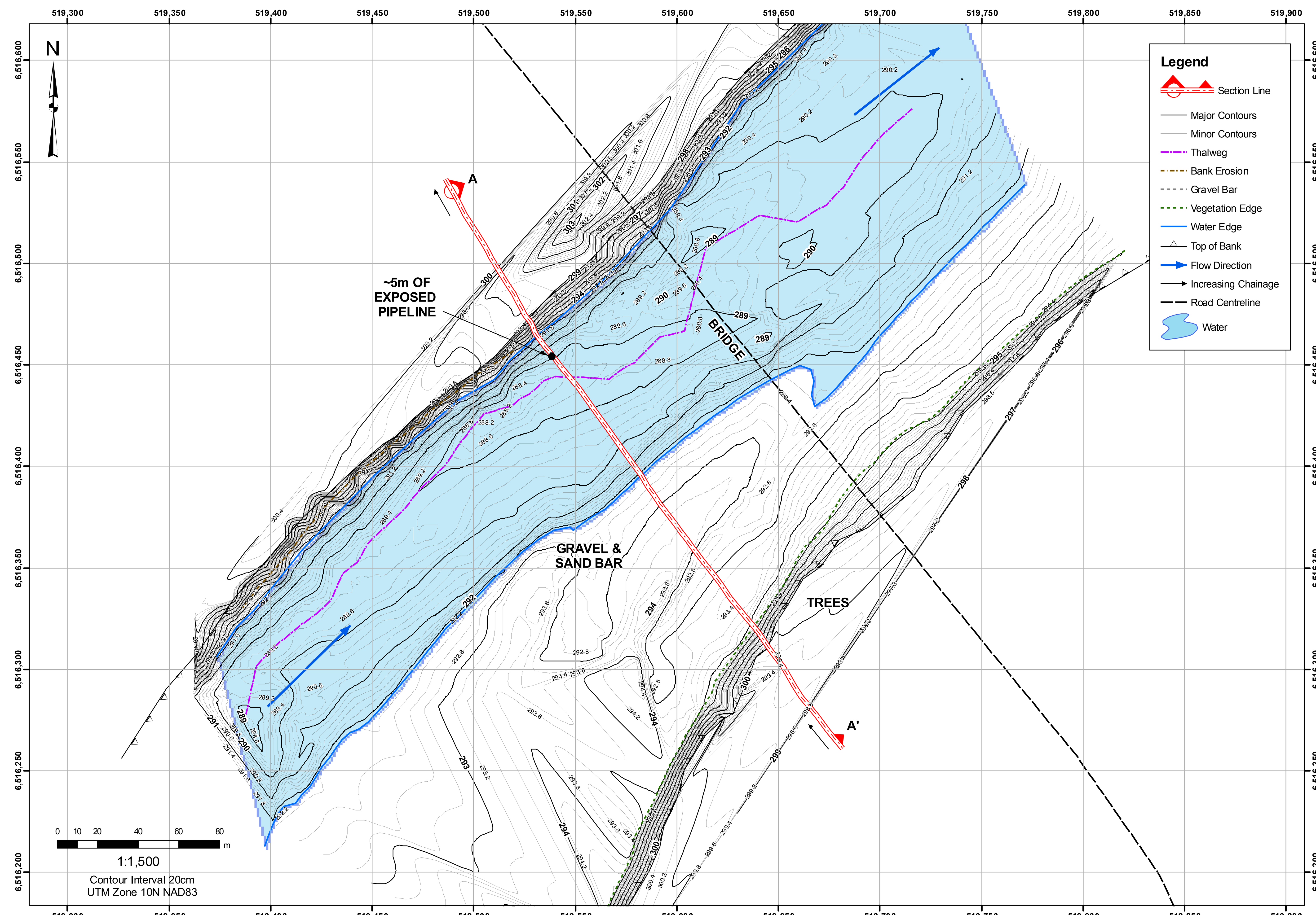
Attachment 21.1

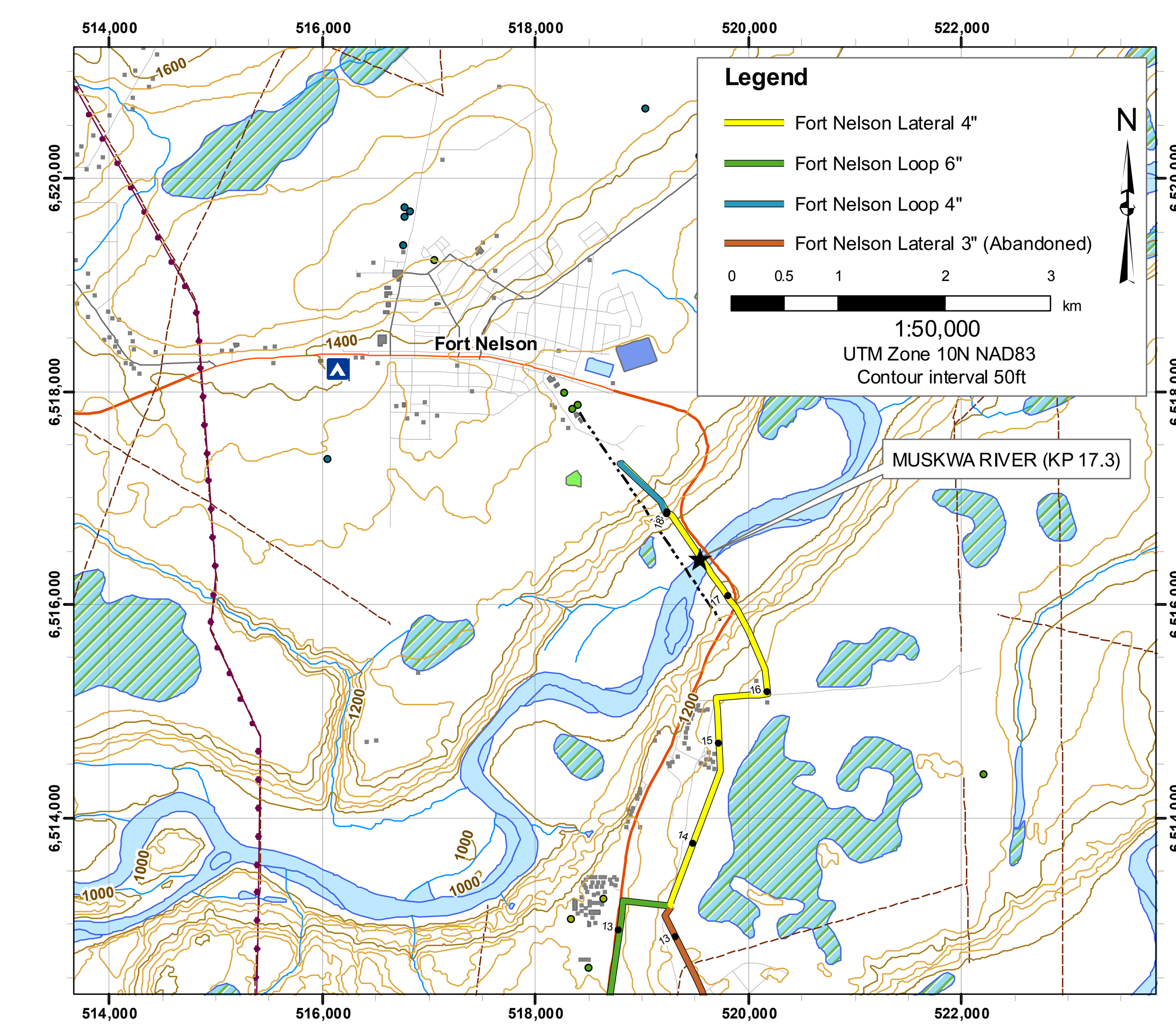
PHOTO 1: Looking upstream from mid-channel over the centreline.

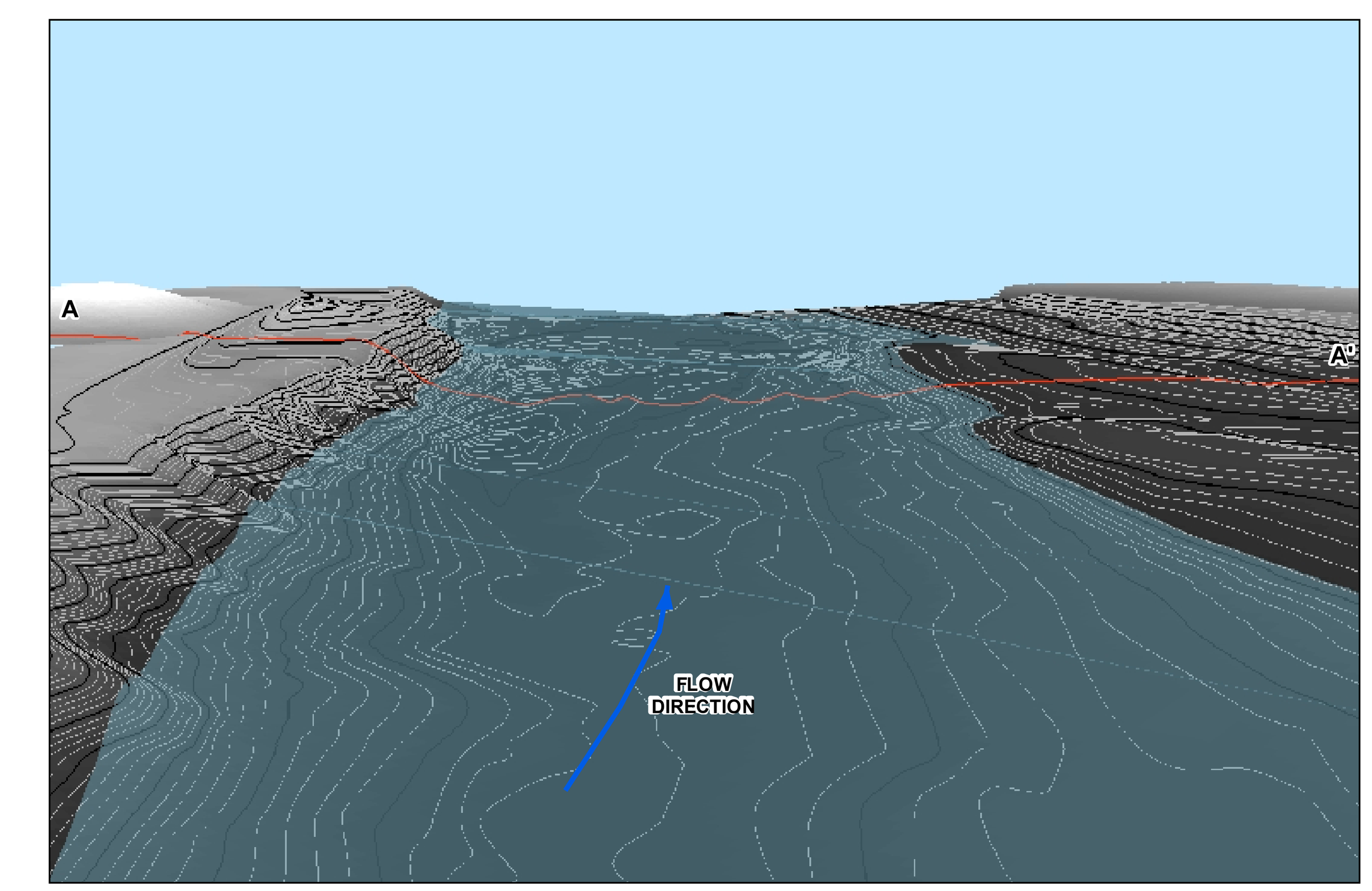
PHOTO 2: Looking at the left (northwest) bank along the centreline from the right bank. The centreline is located at the cut above the diagonally positioned log. Note the bank erosion to the left of the centreline.

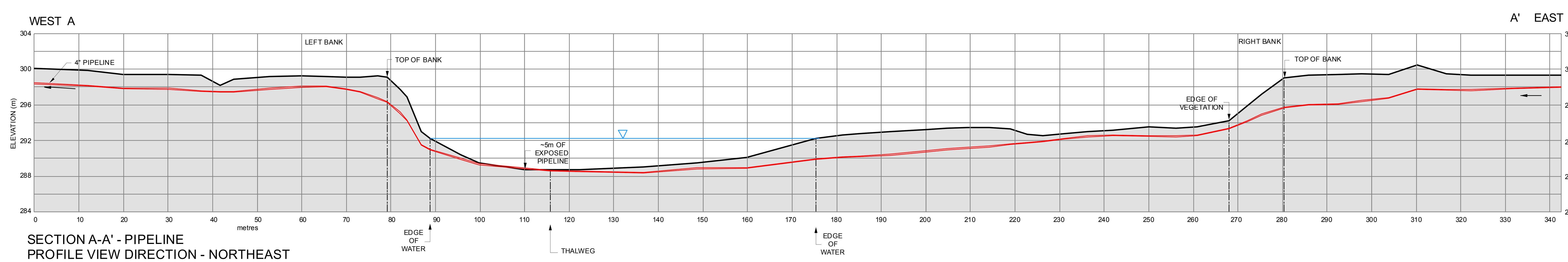
PHOTO 3: Looking downstream at the bridge from mid-channel over the centreline.

PHOTO 4: Looking at the right (southeast) bank along the centreline from the left bank. The subject and the cut between the trees mark the centreline location.









SECTION A-A' - PIPELINE
PROFILE VIEW DIRECTION - NORTHEAST
PROFILE SCALE = 1:600
PROFILE VE = 2x

NOTES:

1. SURVEY COMPLETED ON SEPTEMBER 28, 2008 BY MIDWEST SURVEYS INC.
2. HORIZONTAL DATUM: NAD 83 VERTICAL DATUM: CVD 28.
3. HORIZONTAL POSITIONS ARE BASED ON A UNIVERSAL TRANSVERSE MERCATOR PROJECTION, REFERENCE MERIDIAN 117W Zone 11.
4. ELEVATIONS ARE ORTHOMETRIC HEIGHTS IN METRES, BASED ON GPS OBSERVATIONS AND GEOID MODEL GSD 95.
5. PIPE LOCATION PERFORMED USING A RADIO DETECTION PLX-2 PIPELINE CURRENT MAPPER.
6. GPS LOCATION PERFORMED USING A TRIMBLE R8GNSS RTK SYSTEM SUPPORTED WITH TRIMBLE 5800 ROVER RECEIVERS
7. DEPTH SOUNDING PERFORMED USING A ODOM-ECHOTRAC CV 100 ALL DIGITAL SINGLE BEAM ECHO SOUNDER
8. TOPOGRAPHIC SURVEY PERFORMED USING LEICA TC703 OR TC405 TOTAL STATIONS
9. LOCATION PLAN BASE DATA FROM CANVEC (NATURAL RESOURCES CANADA)

SCALE: AS SHOWN	PROFESSIONAL SEAL: DRAFT	BGC ENGINEERING INC. AN APPLIED EARTH SCIENCES COMPANY	PROJECT: STAGE 3 HYDROTECHNICAL SURVEYS
DATE: OCT 2008			TITLE: MUSKWA RIVER KP 17.3 FORT NELSON LATERAL 4" PIPELINE
DRAWN: MIB		CLIENT: TERASEN GAS INC.	PROJECT No.: 0093-065-04
DESIGNED: AP			DWG No.: 3
CHECKED:			REV.:
APPROVED:			

REV.	DATE	REVISION NOTES	DRAWN	CHECK	APPR.

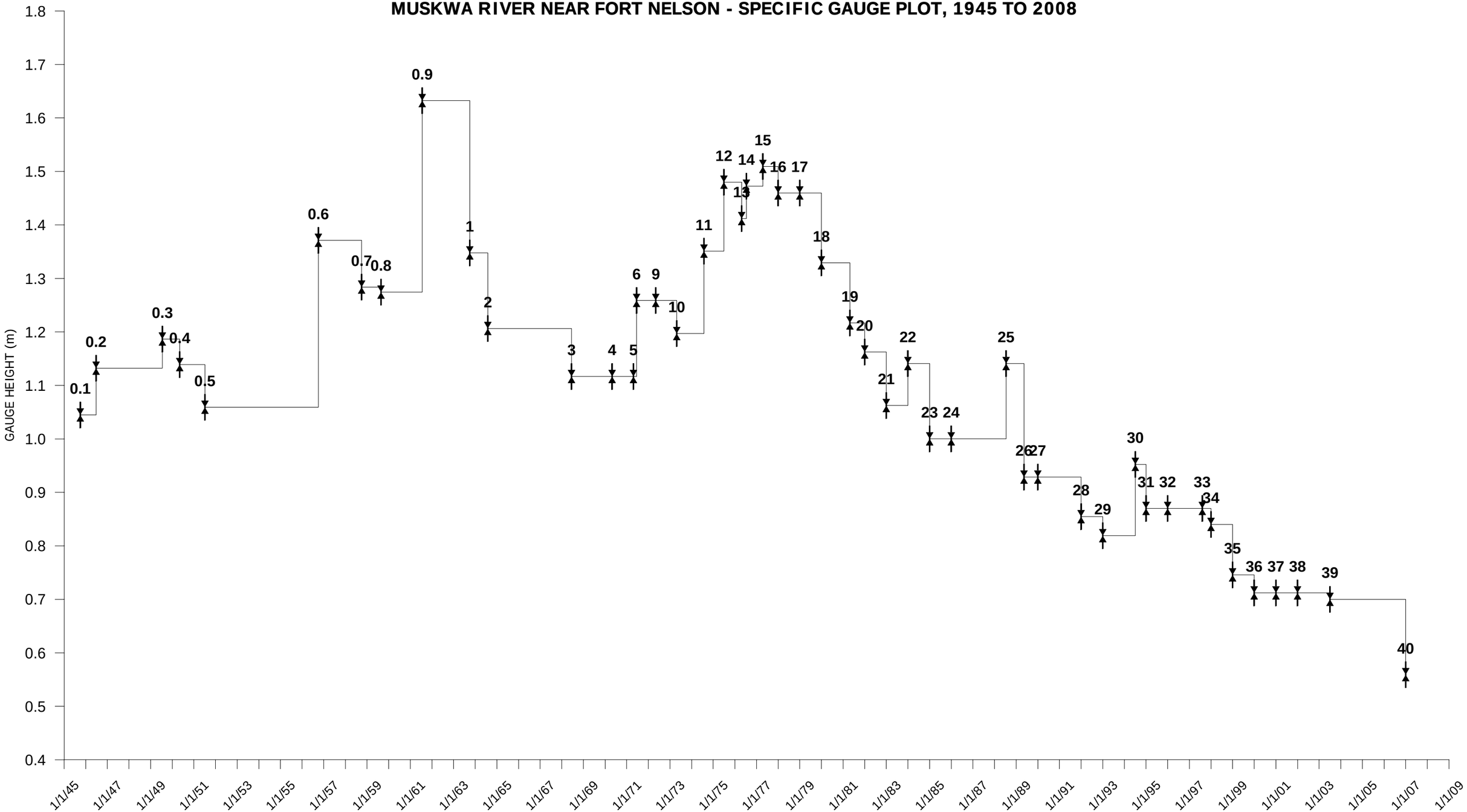
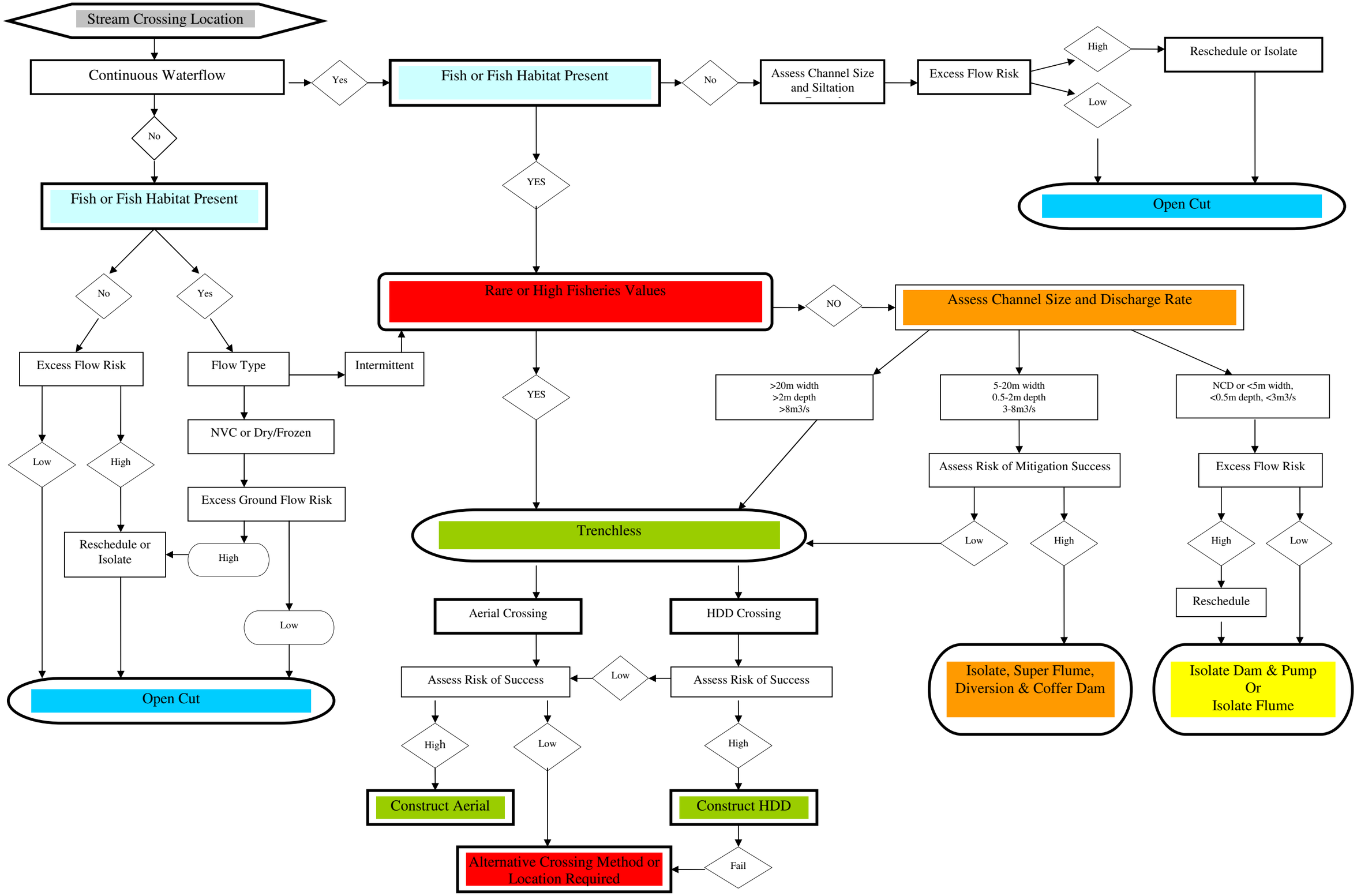


Figure A: Specific gauge plot showing the variation in water levels at a flow of 215 m^3/s over the period between 1945 and 2008.

PIPELINE STREAM CROSSING SELECTION FLOW CHART – October 2006



PRELIMINARY PROJECT SCHEDULE

Project: **Terasen Gas - Muskwa River HDD**

Spread: **HDD Installation**

Length: **480 m**

Resource		MONTH	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		DURATION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH
		Work Days															
DESIGN																	
	Preliminary Design	10d															
	Geotechnical Boreholes & Reporting	15d															
	Fisheries Application	5d															
	Final Design	15d															
PROCUREMENT																	
	Material RFQ	15d															
	Material PO	20d															
	Line Pipe Lead Times to Delivery	240d															
	Valve Lead Times to Delivery	180d															
	Construction Contact - Bid Package	15d															
	Construction Contact - Bidding	30d															
	Construction Contact - Award	1d															
REGULATORY & STAKEHOLDER CONSULTATIONS																	
	Fort Nelson IR consultations	30d															
	OGC Permit Application	15d															
	DFO Application & Letter of Authorization	60d															
	BC FrontCounter Application (land & timber)	60d															
CONSTRUCTION																	
	Construction	43d															
COMMISSION																	
	Hot Tie-ins & Gasification	3d															
OWNER ACCEPTANCE																	
	Project Close-out & Owner Acceptance	15d															

	PROJECT	Muskwa River - HDD Peak to Peak	LENGTH (m)	480
	YEAR	2009	DIA. (mm)	168
	FROM	0+000	W.T. (mm)	11.00
	TO	0+480	S.M.Y.S.(grade)	290
			MAOP. (kPa)	7,960

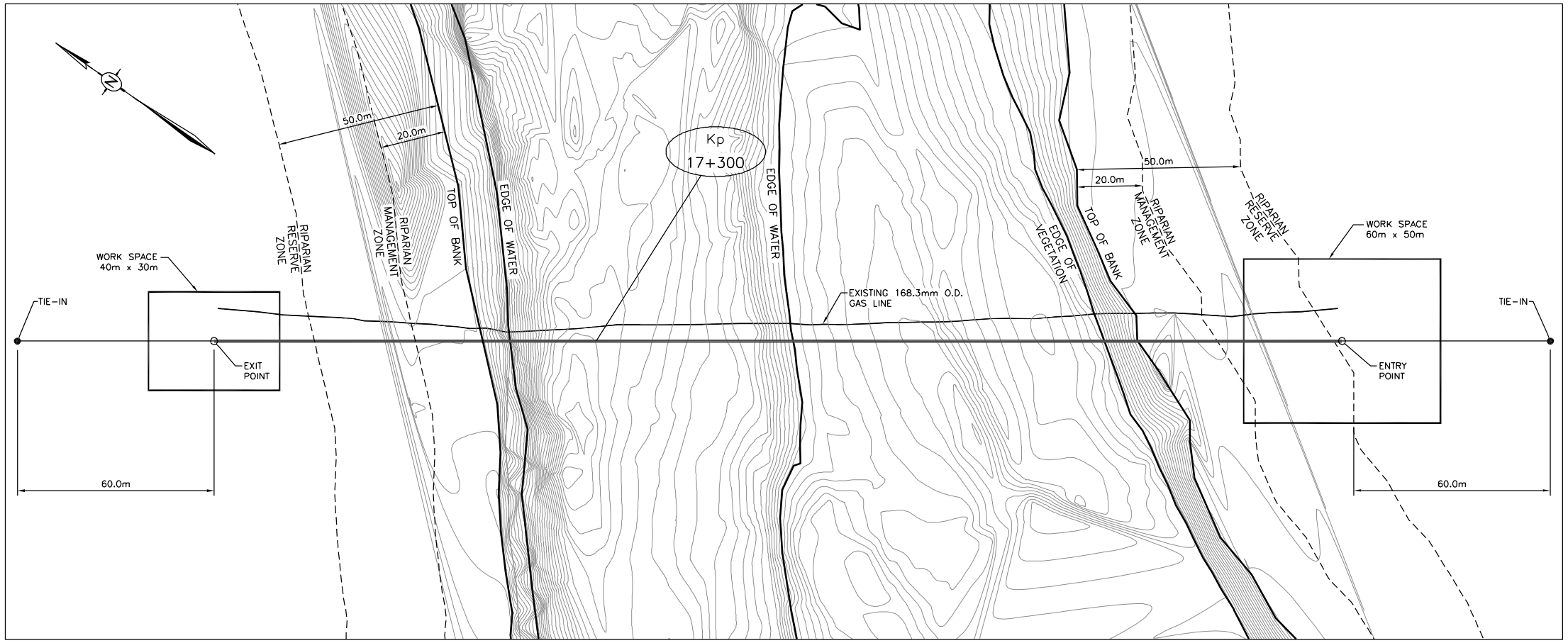
SERVICES

CODE NO.	DESCRIPTION	COMMENTS	UNIT PRICE	NO, OF UNITS	CONSTRUCTION DOLLARS	REFERENCE
401	Base Lay Contract: Clearing		$ 99.82	480	$ 47,911	Resource Worksheet
402	Base Lay Contract: Grading		$ 153.67	480	$ 73,763	Resource Worksheet
403	Base Lay Contract: Stringing		$ 75.89	480	$ 36,429	Resource Worksheet
404	Base Lay Contract: Ditching		$ 60.14	480	$ 28,867	Resource Worksheet
405	Base Lay Contract: Welding		$ 519.32	480	$ 249,272	Resource Worksheet
406	Base Lay Contract: Back Fill / Clean-up		$ 79.10	480	$ 37,968	Resource Worksheet
407	Base Lay Contract: Hydrotesting		$ 206.01	480	$ 98,887	Resource Worksheet
408	Sub Contract: Hydrovac		$ 19.52		$ -	Superior City Quote
409	Sub Contract: NDT		$ 11.06	480	$ 5,309	Cantech Quote
410	Sub Contract: HDD of Muskwa w/ 140,000 lbs Rig		$ 634.57	460	$ 291,902	Entec Quote
411			$ -		$ -	
412			$ -		$ -	
413			$ -		$ -	
414			$ -		$ -	
415	Unit Price Rate: Coating Repairs		$ 50.00	75	$ 3,750	Estimate
416	Unit Price Rate: Traffic Control, Non-Permanent		$ -		$ -	Estimate
417	Unit Price Rate: Weld Destructive Testing		$ 7,000.00		$ -	Estimate
418			$ -		$ -	Estimate
419	Unit Price Rate: Installation of electrical test leads		$ 1,200.00	2	$ 2,400	Estimate
420	Unit Price Rate: ROW Seeding		$ 8.00	1,000	$ 8,000	Estimate
421	Unit Price Rate: Mud Removal and Disposal		$ 500.00	100	$ 50,000	Estimate
422	Unit Price Rate: Pipeline Sand Padding		$ 97.50	100	$ 9,750	Blue Canyon
423	Unit Price Rate: Road Aggregate Import		$ 105.00	100	$ 10,500	Blue Canyon
424	Unit Price Rate: Rip Rap D50 Import		$ 150.00		$ -	Blue Canyon
425	Unit Price Rate: Air drying pipeline		$ 25,000.00		$ -	Estimate
426	Unit Price Rate: Installation of warning signs		$ 150.00	6	$ 900	Estimate
427	Unit Price Rate: Installation of Ditch Plugs		$ -		$ -	Estimate
428	Mark ups: Material		$ -		$ -	Estimate
429	Mark ups: Third Party	Incl in Sub Cost	$ -		$ -	Estimate
430	Misc. Expenses		$ -		$ -	Estimate
	TOTAL CONSTRUCTION				**$ 955,608**	
					$ 1,991	**/ meter Construction**
	ENGINEERING & INSPECTION					
101	Design Engineering (EPCM)		$ 50,000	1	$ 50,000	Task Sheet
102	Land Services & Permitting		$ 20,000	1	$ 20,000	Task Sheet
103	Geotechnical Investigation (8 boreholes)		$ 135,000	1	$ 135,000	Coffey Geotechnics
104	Surveys		$ 3.85	480	$ 1,848	Bennet Land Survey
105	Environmental Field Inspection				$ -	Estimate
106	Field Inspection & Pipeline QA		$ 3,100	43	$ 133,279	Resource Worksheet
108	Gauge Pigging and Biocide Run		$ -	-	$ -	Estimate
109	Engineering Support during Construction		$ 1,500	5	$ 7,500	Estimate
111	Shop Inspections		$ -	-	$ -	Estimate
112	Mill Inspections		$ 15,000	-	$ -	Estimate
	TOTAL ENGINEERING & INSPECTION				**$ 347,627**	
	COMMISSIONING					
501	Engineering Commissioning Support		$ 1,500	5	$ 7,500	Resource Worksheet
502	Terasen Gas Transmission Crew for Hot Tie-ins		$ 12,855	3	$ 38,565	Resource Worksheet
503	Operating Procedures					
504	Training					
	TOTAL COMMISSIONING				**$ 46,065**	

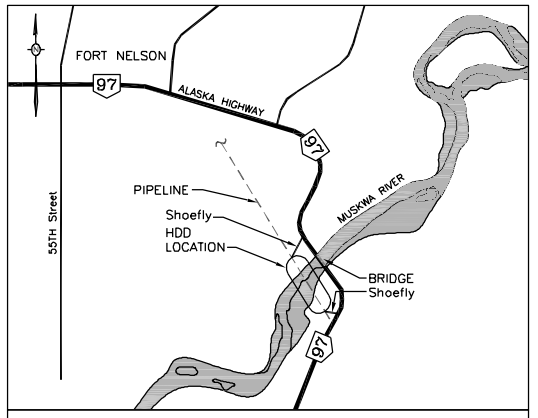
MATERIALS

CODE NO.	DESCRIPTION	MATERIALS QUANTITY		UNIT PRICE		MATERIAL DOLLARS	WBS
301	Line Pipe (Z662)	460		$ 110		$ 50,600	Quote
303	Line Pipe Coating - DPS	460		$ 30		$ 13,800	Quote
303	Joint Coatings - Heat Shrink Sleeves	38		$ 25		$ 941	Quote
303	Joint Coatings - HDD Heat Shrink Sleeves	38		$ 53		$ 2,028	Quote
311	Cathodic Protection	0		$ -	-	$ -	
329	Buoyancy Control	0		$ -	-	$ -	
330	Valve Station Materials	0		$ -		$ -	
343	Pig Barrel Materials	0		$ -		$ -	
344	Induction Bends	0		$ -		$ -	
345	Corrosion Inhibition Chemicals	0		$ -		$ -	
350	Freight & Hauling	0		$ -		$ -	
399	Misc. Equipment	0		$ -		$ -	
	SUB-TOTAL					**$ 67,369**	
	PROVINCIAL SALES TAX					**$ 4,716**	
	TOTAL MATERIALS					**$ 72,085**	

		sub-total	**$ 1,421,000**
	CONTINGENCY (15%)	**$**	**213,150**
	GRAND TOTAL	**$**	**1,634,150**
	per m	**$**	**3,404 /M**



PLAN
SCALE: 1:750



LOCATION PLAN
SCALE: N.T.S.

GENERAL LOCATION

KILOMETER POST:	17+300
NTS LAND LOCATION:	B-043-B / 094-J-15
UTM ZONE:	10N NAD83, N6516320.243, E519639.591

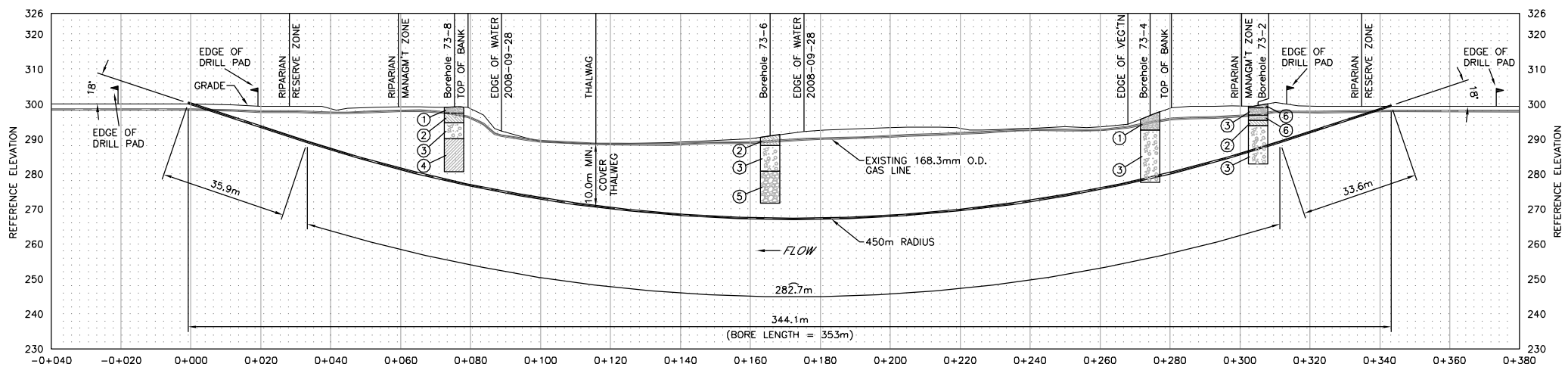
MATERIAL LIST

ITEM	QTY.	DESCRIPTION	REF. DWG.
1	480m	168.3mm X 7.11mm W.T., GR 290, CSA Z245.1,	---
		CAT II, DPS COATING, DBL RANDOM, ERW	

CLASS LOCATION: 3
OVERALL SAFETY FACTOR: 56%
M.O.P. 7960 kPa

DESIGN NOTES

1. CROSSING SECTION - TEST PRESSURE
   MINIMUM = 11 144 kPa
   MAXIMUM = 15 000 kPa
   DURATION = 24 HOURS
2. DESIGN TEMPERATURE - M45C.



PROFILE
SCALE: 1:750

CONSTRUCTION NOTES

1. MINIMUM DEPTH OF COVER: 1.2m (GENERAL) AND 10.0m (RIVER & FLOOD PLAIN).
2. ALL WELDS, INCLUDING TIE-INS, SHALL BE NON-DESTRUCTIVELY INSPECTED FOR 100% OF CIRCUMFERENCE TO ACCEPTABLE CRITERIA OF WELD PROCEDURE (CSA), AND ALL RECORDS MAINTAINED.
3. ALL JOINT COATINGS SHALL BE PRE-HEATED, SANDBLASTED TO SSPC-10 AND COATED WITH ABRASION RESISTANT EPOXY.
4. JOINTS SHALL BE HOLIDAY TESTED BEFORE LOWERING AND REPAIRS UNDERTAKEN AND RE-INSPECTED.
5. PREBUILT SECTION SHALL BE HYDROSTATICALLY TESTED PRIOR TO INSTALLATION BY HDD.
6. SILT FENCING IS A SUITABLE SUBSTITUTE FOR A SOIL BERM.
7. CONDUCTIVITY TESTING SHALL BE COMPLETED POST INSTALLATION.

① - SILT, SAND, GRAVEL
② - SILT, SAND
③ - SAND, GRAVEL
④ - SAND, GRAVEL, COBBLES, BOULDERS
⑤ - COBBLES, BOULDERS
⑥ - SAND

CHINOOK ENGINEERING	R0	ISSUED FOR COMMENT	DAH	DB	DAE	10-03-04
BY	No.	REVISION	DRAWN	DESIGNED	CHECKED	DATE(YY-MM-DD)
PREVIOUS DR. NO.-		SAP ID:		MICROFILMED		SCALE- AS SHOWN

Terasen Gas

ENGINEER SEAL

168.3mm TP - MUSKWA PIPELINE

PRELIMINARY DESIGN
HORIZONTAL DIRECTIONAL DRILL OF THE MUSKWA RIVER AT Kp 17+300
PLAN AND PROFILE

DRAWING NUMBER 32004-P-000-1000-R0

Attachment 21.1

PRELIMINARY PROJECT SCHEDULE

Project: **Terasen Gas - Muskwa River HDD**

Spread: **HDD Installation - Low to High**

Length: **380 m**

Resource		MONTH	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		DURATION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH
		Work Days															
DESIGN																	
	Preliminary Design	10d															
	Geotechnical Boreholes & Reporting	15d															
	Fisheries Application	5d															
	Final Design	15d															
PROCUREMENT																	
	Material RFQ	15d															
	Material PO	20d															
	Line Pipe Lead Times to Delivery	240d															
	Valve Lead Times to Delivery	180d															
	Construction Contact - Bid Package	15d															
	Construction Contact - Bidding	30d															
	Construction Contact - Award	1d															
REGULATORY & STAKEHOLDER CONSULTATIONS																	
	Fort Nelson IR consultations	30d															
	OGC Permit Application	15d															
	DFO Application & Letter of Authorization	60d															
	BC FrontCounter Application (land & timber)	60d															
CONSTRUCTION																	
	Construction	43d															
COMMISSION																	
	Hot Tie-ins & Gasification	3d															
OWNER ACCEPTANCE																	
	Project Close-out & Owner Acceptance	15d															

	PROJECT	Muskwa River - HDD Low to High		LENGTH (m)	380
	YEAR	2009		DIA. (mm)	168
	FROM	0+000		W.T. (mm)	11.00
	TO	0+380		S.M.Y.S.(grade)	290
				MAOP. (kPa)	7,960

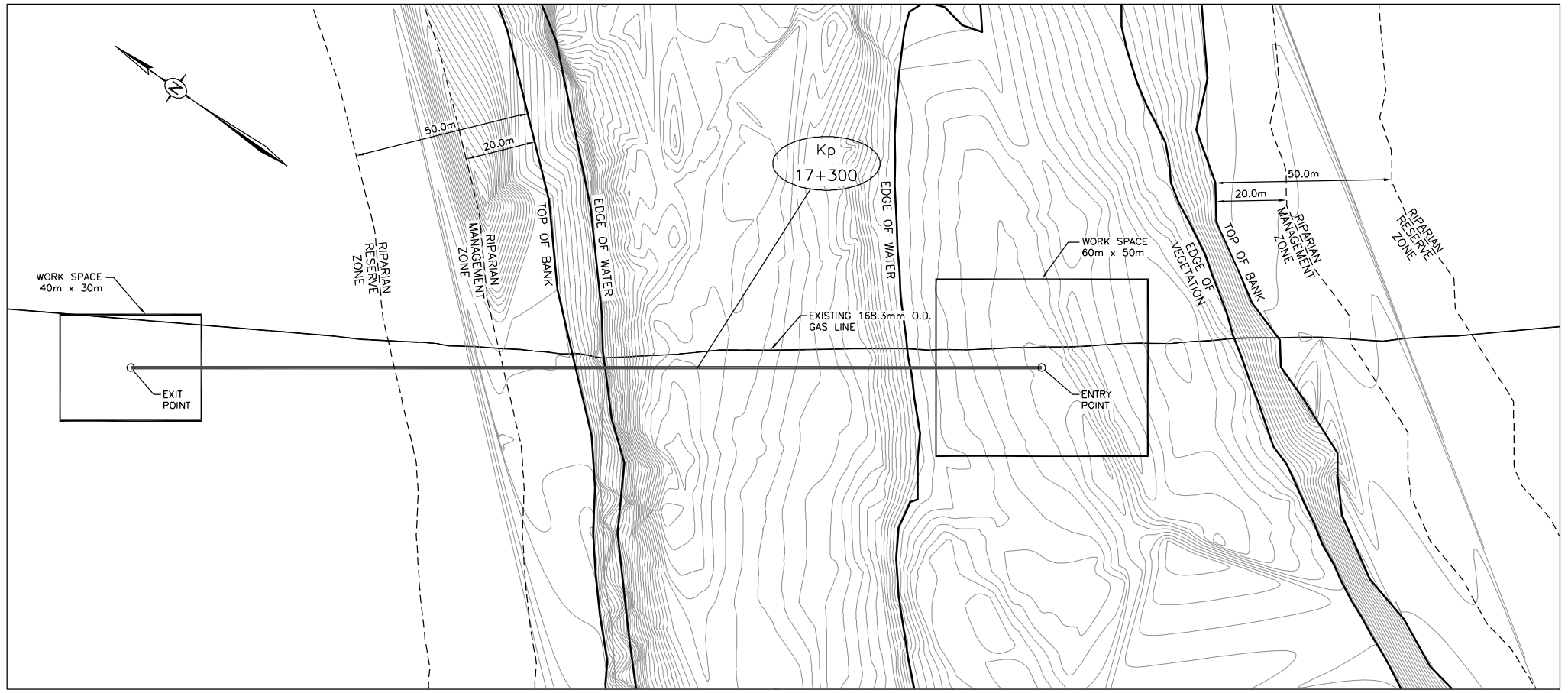
SERVICES

CODE NO.	DESCRIPTION	COMMENTS	UNIT PRICE	NO, OF UNITS	CONSTRUCTION DOLLARS	REFERENCE
401	Base Lay Contract: Clearing		$ 126.08	380	$ 47,911	Resource Worksheet
402	Base Lay Contract: Grading		$ 194.11	380	$ 73,763	Resource Worksheet
403	Base Lay Contract: Stringing		$ 95.87	380	$ 36,429	Resource Worksheet
404	Base Lay Contract: Ditching		$ 75.96	380	$ 28,867	Resource Worksheet
405	Base Lay Contract: Welding		$ 655.98	380	$ 249,272	Resource Worksheet
406	Base Lay Contract: Back Fill / Clean-up		$ 99.92	380	$ 37,968	Resource Worksheet
407	Base Lay Contract: Hydrotesting		$ 260.23	380	$ 98,887	Resource Worksheet
408	Sub Contract: Hydrovac		$ 19.52		$ -	Superior City Quote
409	Sub Contract: NDT		$ 13.52	380	$ 5,138	Cantech Quote
410	Sub Contract: HDD of Muskwa w/ 140,000 lbs Rig		$ 674.72	270	$ 182,175	Entec Quote
411			$ -		$ -	
412			$ -		$ -	
413			$ -		$ -	
414			$ -		$ -	
415	Unit Price Rate: Coating Repairs		$ 50.00	75	$ 3,750	Estimate
416	Unit Price Rate: Traffic Control, Non-Permanent		$ -		$ -	Estimate
417	Unit Price Rate: Weld Destructive Testing		$ 7,000.00		$ -	Estimate
418			$ -		$ -	Estimate
419	Unit Price Rate: Installation of electrical test leads		$ 1,200.00	2	$ 2,400	Estimate
420	Unit Price Rate: ROW Seeding		$ 8.00	1,000	$ 8,000	Estimate
421	Unit Price Rate: Mud Removal and Disposal		$ 500.00	100	$ 50,000	Estimate
422	Unit Price Rate: Pipeline Sand Padding		$ 97.50	100	$ 9,750	Blue Canyon
423	Unit Price Rate: Road Aggregate Import		$ 105.00	100	$ 10,500	Blue Canyon
424	Unit Price Rate: Rip Rap D50 Import		$ 150.00		$ -	Blue Canyon
425	Unit Price Rate: Air drying pipeline		$ 25,000.00		$ -	Estimate
426	Unit Price Rate: Installation of warning signs		$ 150.00	6	$ 900	Estimate
427	Unit Price Rate: Installation of Ditch Plugs		$ -		$ -	Estimate
428	Mark ups: Material		$ -		$ -	Estimate
429	Mark ups: Third Party	Incl in Sub Cost	$ -		$ -	Estimate
430	Misc. Expenses		$ -		$ -	Estimate
	TOTAL CONSTRUCTION				**$ 845,709**	
					$ 2,226	**/ meter Construction**
	ENGINEERING & INSPECTION					
101	Design Engineering (EPCM)		$ 50,000	1	$ 50,000	Task Sheet
102	Land Services & Permitting		$ 20,000	1	$ 20,000	Task Sheet
103	Geotechnical Investigation (8 boreholes)		$ 135,000	1	$ 135,000	Coffey Geotechnics
104	Surveys		$ 3.85	380	$ 1,463	Bennet Land Survey
105	Environmental Field Inspection				$ -	Estimate
106	Field Inspection & Pipeline QA		$ 3,100	43	$ 133,279	Resource Worksheet
108	Gauge Pigging and Biocide Run		$ -	-	$ -	Estimate
109	Engineering Support during Construction		$ 1,500	5	$ 7,500	Estimate
111	Shop Inspections		$ -	-	$ -	Estimate
112	Mill Inspections		$ 15,000	-	$ -	Estimate
	TOTAL ENGINEERING & INSPECTION				**$ 347,242**	
	COMMISSIONING					
501	Engineering Commissioning Support		$ 1,500	5	$ 7,500	Resource Worksheet
502	Terasen Gas Transmission Crew for Hot Tie-ins		$ 12,855	3	$ 38,565	Resource Worksheet
503	Operating Procedures					
504	Training					
	TOTAL COMMISSIONING				**$ 46,065**	

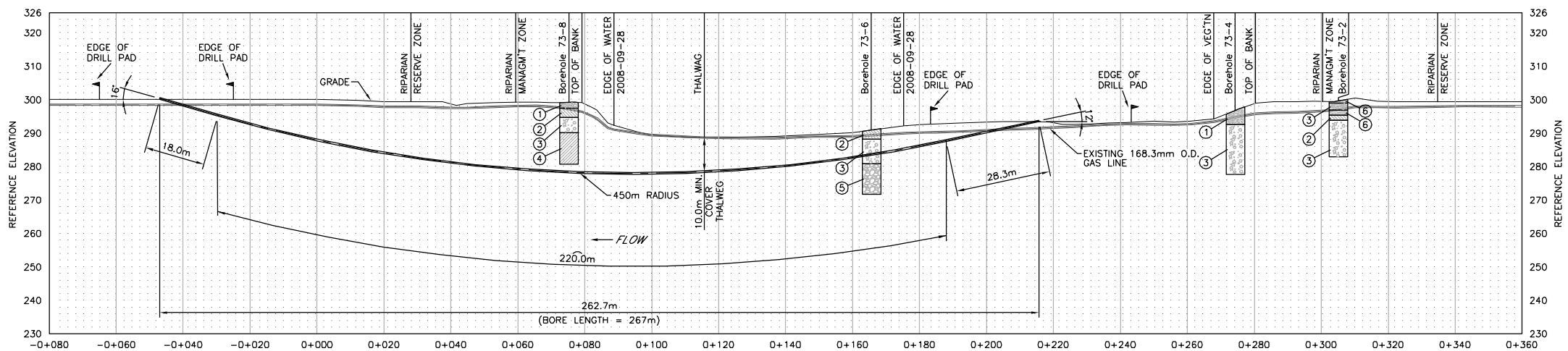
MATERIALS

CODE NO.	DESCRIPTION	MATERIALS QUANTITY		UNIT PRICE		MATERIAL DOLLARS	WBS
301	Line Pipe (Z662)	380		$ 110		$ 41,800	Quote
303	Line Pipe Coating - DPS	380		$ 30		$ 11,400	Quote
303	Joint Coatings - Heat Shrink Sleeves	32		$ 25		$ 777	Quote
303	Joint Coatings - HDD Heat Shrink Sleeves	32		$ 53		$ 1,675	Quote
311	Cathodic Protection	0		$ -	-	$ -	
329	Buoyancy Control	0		$ -	-	$ -	
330	Valve Station Materials	0		$ -		$ -	
343	Pig Barrel Materials	0		$ -		$ -	
344	Induction Bends	0		$ -		$ -	
345	Corrosion Inhibition Chemicals	0		$ -		$ -	
350	Freight & Hauling	0		$ -		$ -	
399	Misc. Equipment	0		$ -		$ -	
	SUB-TOTAL					**$ 55,653**	
	PROVINCIAL SALES TAX					**$ 3,896**	
	TOTAL MATERIALS					**$ 59,548**	

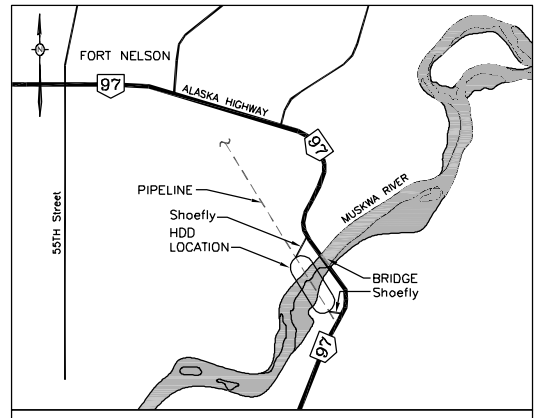
sub-total	**$ 1,299,000**	
CONTINGENCY (15%)	**$ 194,850**	
GRAND TOTAL	**$ 1,493,850**	
per m	**$ 3,931**	**/M**



PLAN
SCALE: 1:750



PROFILE
SCALE: 1:750



LOCATION PLAN
SCALE: N.T.S.

GENERAL LOCATION

KILOMETER POST:	17+300
NTS LAND LOCATION:	B-043-B / 094-J-15
UTM ZONE:	10N NAD83, N6516320.243, E519639.591

MATERIAL LIST

ITEM	QTY.	DESCRIPTION	REF. DWG.
1	270m	168.3mm X 7.11mm W.T., GR 290, CSA Z245.1,	---
		CAT II, DPS COATING, DBL RANDOM, ERW	

CLASS LOCATION: 3
OVERALL SAFETY FACTOR: 56%
M.O.P. 7960 kPa

DESIGN NOTES

1. CROSSING SECTION - TEST PRESSURE
   MINIMUM = 11 144 kPa
   MAXIMUM = 15 000 kPa
   DURATION = 24 HOURS
2. DESIGN TEMPERATURE - M45C.

CONSTRUCTION NOTES

1. MINIMUM DEPTH OF COVER: 1.2m (GENERAL), 2.5m RIVER AND FLOOD PLAIN AND 10.0m AT THALWAG.
2. ALL WELDS, INCLUDING TIE-INS, SHALL BE NON-DESTRUCTIVELY INSPECTED FOR 100% OF CIRCUMFERENCE TO ACCEPTABLE CRITERIA OF WELD PROCEDURE (CSA), AND ALL RECORDS MAINTAINED.
3. ALL JOINT COATINGS SHALL BE PRE-HEATED, SANDBLASTED TO SSPC-10 AND COATED WITH ABRASION RESISTANT EPOXY.
4. JOINTS SHALL BE HOLIDAY TESTED BEFORE LOWERING AND REPAIRS UNDERTAKEN AND RE-INSPECTED.
5. PREBUILT SECTION SHALL BE HYDROSTATICALLY TESTED PRIOR TO INSTALLATION BY HDD.
6. SILT FENCING IS A SUITABLE SUBSTITUTE FOR A SOIL BERM.
7. CONDUCTIVITY TESTING SHALL BE COMPLETED POST INSTALLATION.

① - SILT, SAND, GRAVEL
② - SILT, SAND
③ - SAND, GRAVEL
④ - SAND, GRAVEL, COBBLES, BOULDERS
⑤ - COBBLES, BOULDERS
⑥ - SAND

CHINOOK ENGINEERING	R0	ISSUED FOR COMMENT	DAH	DB	DAE	10-03-04
BY	No.	REVISION	DRAWN	DESIGNED	CHECKED	DATE(YY-MM-DD)
PREVIOUS DR. NO.-		SAP ID:		MICROFILMED		SCALE- AS SHOWN

Terasen Gas

ENGINEER SEAL

168.3mm TP - MUSKWA PIPELINE

PRELIMINARY DESIGN
HORIZONTAL DIRECTIONAL DRILL OF THE MUSKWA RIVER AT Kp 17+300
LOW TO HIGH - PLAN AND PROFILE

DRAWING NUMBER 32004-P-000-1005-R0

Attachment 21.1

PRELIMINARY PROJECT SCHEDULE

Project: **Terasen Gas - Muskwa River HDD**

Spread: **Open Cut Crossing**

Length: **300 m**

Resource		MONTH	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
		DURATION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER
		Work Days																					
DESIGN																							
	Preliminary Design	10d																					
	Fish & Fish Habitat Assessment	20d																					
	Fisheries Application	5d																					
	Final Design	15d																					
PROCUREMENT																							
	Material RFQ	15d																					
	Material PO	20d																					
	Line Pipe Lead Times to Delivery	240d																					
	Valve Lead Times to Delivery	180d																					
	Construction Contact - Bid Package	15d																					
	Construction Contact - Bidding	30d																					
	Construction Contact - Award	1d																					
REGULATORY & STAKEHOLDER CONSULTATIONS																							
	Fort Nelson IR consultations	30d																					
	OGC Permit Application	15d																					
	DFO Application & Letter of Authorization	60d																					
	BC FrontCounter Application (land & timber)	60d																					
CONSTRUCTION																							
	Construction	35d																					
COMMISSION																							
	Hot Tie-ins & Gasification	3d																					
OWNER ACCEPTANCE																							
	Project Close-out & Owner Acceptance	15d																					

	PROJECT	Muskwa River - Open Cut		LENGTH (m)	300
	YEAR	2009		DIA. (mm)	168
	FROM	0+000		W.T. (mm)	11.00
	TO	0+300		S.M.Y.S.(grade)	290
				MAOP. (kPa)	7,960

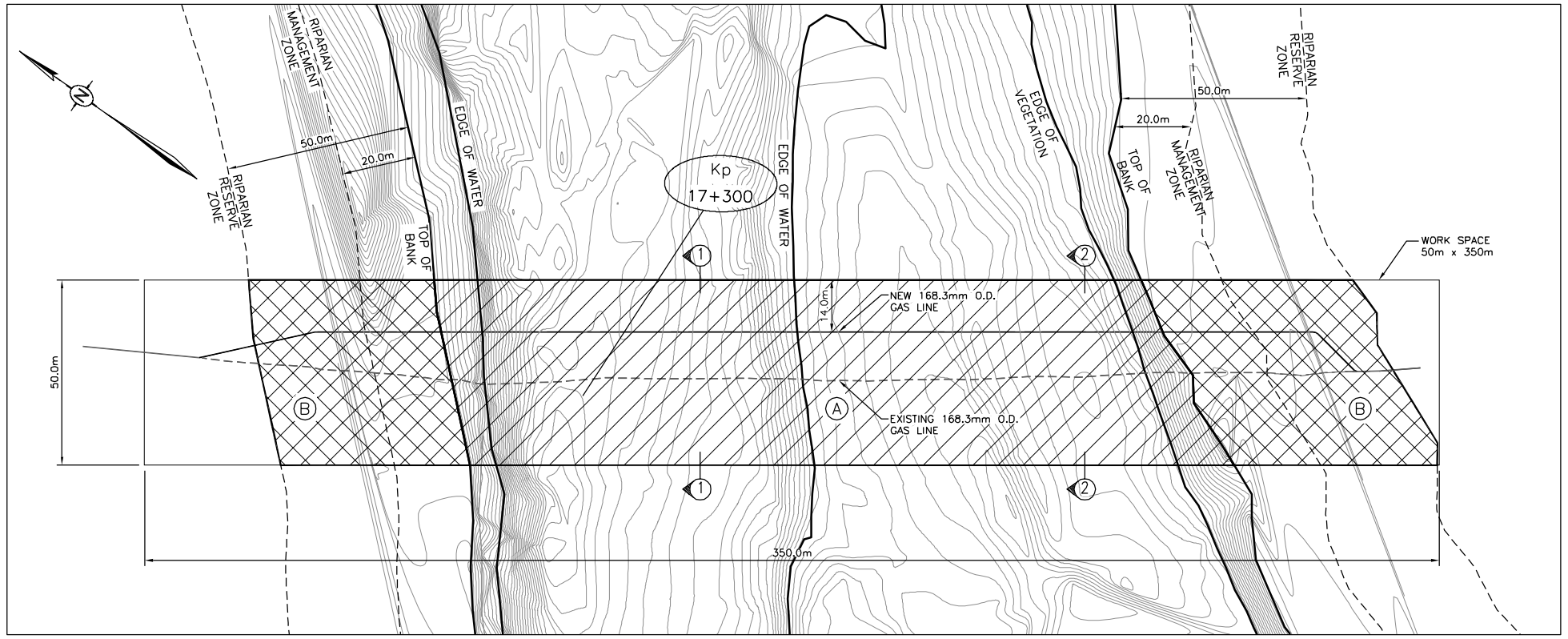
SERVICES

CODE NO.	DESCRIPTION	COMMENTS	UNIT PRICE	NO, OF UNITS	CONSTRUCTION DOLLARS	REFERENCE
401	Base Lay Contract: Clearing		$ 283.85	300	$ 85,154	Resource Worksheet
402	Base Lay Contract: Grading		$ 249.44	300	$ 74,833	Resource Worksheet
403	Base Lay Contract: Stringing		$ 112.29	300	$ 33,687	Resource Worksheet
404	Base Lay Contract: Ditching		$ 259.90	300	$ 77,970	Resource Worksheet
405	Base Lay Contract: Welding		$ 692.82	300	$ 207,846	Resource Worksheet
406	Base Lay Contract: Back Fill		$ 489.21	300	$ 146,764	Resource Worksheet
407	Base Lay Contract: Hydrotesting		$ 125.92	300	$ 37,777	Resource Worksheet
408	Sub Contract: Hydrovac		$ 19.52		$ -	Superior City Quote
409	Sub Contract: NDT		$ 12.21	300	$ 3,663	Cantech Quote
410			$ -		$ -	
411			$ -		$ -	
412			$ -		$ -	
413			$ -		$ -	
414			$ -		$ -	
415	Unit Price Rate: Coating Repairs		$ 50.00	75	$ 3,750	Estimate
416	Unit Price Rate: Traffic Control, Non-Permanent		$ -		$ -	
417	Unit Price Rate: Weld Destructive Testing		$ -		$ -	
418			$ -		$ -	
419	Unit Price Rate: Installation of electrical test leads		$ 1,200.00	2	$ 2,400	Estimate
420	Unit Price Rate: ROW Seeding		$ 8.00	1,000	$ 8,000	Estimate
421	Unit Price Rate: 3/4 Minus Import		$ 135.00	10	$ 1,350	Blue Canyon
422	Unit Price Rate: Pipeline Sand Padding		$ 97.50	54	$ 5,265	Blue Canyon
423	Unit Price Rate: Road Aggregate Import		$ 105.00	420	$ 44,100	Blue Canyon
424	Unit Price Rate: Rip Rap D50 Import		$ 150.00	900	$ 135,000	Blue Canyon
425	Unit Price Rate: Air drying pipeline		$ 25,000.00		$ -	Estimate
426	Unit Price Rate: Installation of warning signs		$ 150.00	6	$ 900	Estimate
427	Unit Price Rate: Installation of Ditch Plugs		$ 5,000.00	2	$ 10,000	Estimate
428	Mark ups: Material		$ -		$ -	Estimate
429	Mark ups: Third Party	Incl in Sub Cost	$ -		$ -	Estimate
430	Misc. Expenses		$ -		$ -	Estimate
	TOTAL CONSTRUCTION				**$ 878,460**	
					$ 2,928	**/ meter Construction**
	ENGINEERING & INSPECTION					
101	Design Engineering (EPCM)		$ 25,000	1	$ 25,000	Task Sheet
102	Land Services & Permitting		$ 10,000	1	$ 10,000	Task Sheet
103	Geotechnical Investigation (boreholes)		$ -		$ -	Estimate
104	Surveys		$ 12.43	300	$ 3,729	Bennet Land Survey
105	Environmental Field Inspection				$ -	Estimate
106	Field Inspection & Pipeline QA		$ 3,523	35	$ 123,296	Resource Worksheet
108	Gauge Pigging and Biocide Run		$ -		$ -	Estimate
109	Shop Inspections		$ -		$ -	Estimate
111	Mill Inspections		$ 15,000		$ -	Estimate
112	HADD Environmental Remediation (2:1 ratio for disturbance)		$ 10	30,700	$ 307,000	Estimate
	TOTAL ENGINEERING & INSPECTION				**$ 469,025**	
	COMMISSIONING					
501	Engineering Commissioning Support		$ 1,500	5	$ 7,500	Resource Worksheet
502	Terasen Gas Transmission Crew for Hot Tie-ins (incl. above)		$ 12,855	3	$ 38,565	Resource Worksheet
503	Operating Procedures					
504	Training					
	TOTAL COMMISSIONING				**$ 46,065**	

MATERIALS

CODE NO.	DESCRIPTION	MATERIALS QUANTITY		UNIT PRICE		MATERIAL DOLLARS	WBS
301	Line Pipe (Z662) w/ DPS Coating	300		$ 140		$ 42,000	Quote
303	Line Pipe Coating - Concrete overcoat	300		$ 30		$ 9,000	Quote
303	Joint Coatings - Heat Shrink Sleeves	25		$ 25		$ 614	Quote
303	Joint Coatings - HDD Heat Shrink Sleeves	0		$ 53		$ -	Quote
311	Barge Rental	40	d	$ 3,500		$ 140,000	Cooper Barging Service
329	Buoyancy Control	0	ea	$ 500	-	$ -	
330	Valve Station Materials	0		$ -		$ -	
343	Pig Barrel Materials	0		$ -		$ -	
344	Induction Bends	0		$ -		$ -	
345	Corrosion Inhibition Chemicals	0		$ -		$ -	
350	Freight & Hauling	0		$ -		$ -	
399	Misc. Equipment	0		$ -		$ -	
	SUB-TOTAL					**$ 191,614**	
	PROVINCIAL SALES TAX					**$ 13,413**	
	TOTAL MATERIALS					**$ 205,027**	
					sub-total	**$ 1,599,000**	

CONTINGENCY (15%)	**$**	**239,850**
GRAND TOTAL	**$**	**1,838,850**
per m	**$**	**6,130** /M



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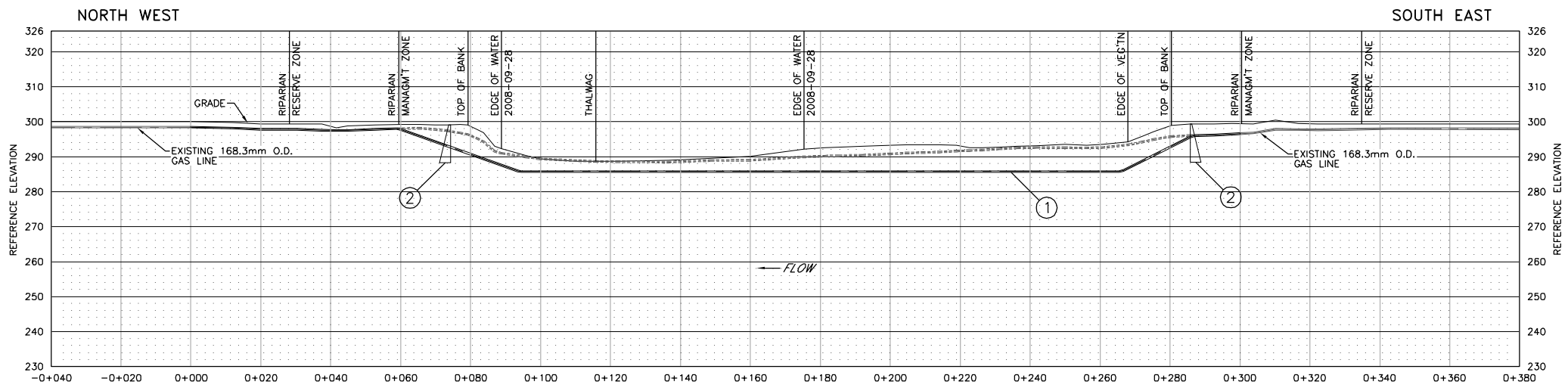

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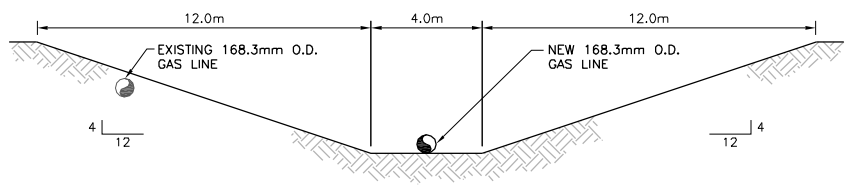
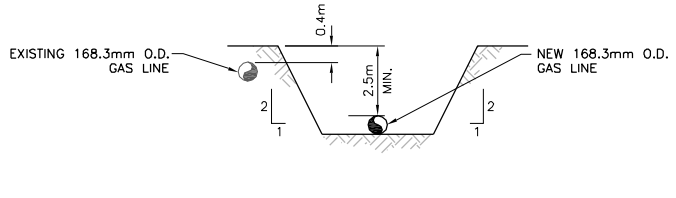


1 SCALE N.T.S.



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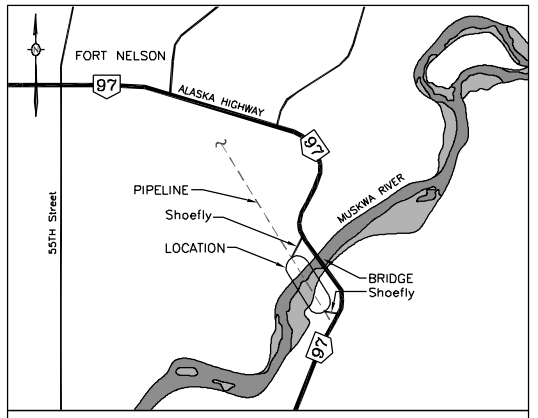


LOCATION PLAN
SCALE: N.T.S.

GENERAL LOCATION

KILOMETER POST:	17+300
NTS LAND LOCATION:	B-043-B / 094-J-15
UTM ZONE:	10N NAD83, N6516320.243, E519639.591

MATERIAL LIST

ITEM	QTY.	DESCRIPTION	REF. DWG.
1	300m	168.3mm X 7.11mm W.T., GR 290, CSA Z245.1,	---
		CAT II, DPS COATING, DBL RANDOM, ERW	
		CONCRETE OVERCOAT	
2	2	DITCH PLUGS	

CLASS LOCATION: 3
OVERALL SAFETY FACTOR: 56%
M.O.P. 7960 kPa

DESIGN NOTES

1. CROSSING SECTION - TEST PRESSURE
   MINIMUM = 11 144 kPa
   MAXIMUM = 15 000 kPa
   DURATION = 24 HOURS
2. DESIGN TEMPERATURE - M45C.

CONSTRUCTION NOTES

1. MINIMUM DEPTH OF COVER: 1.2m (GENERAL) AND 2.5m (RIVER & FLOOD PLAIN).
2. ALL WELDS, INCLUDING TIE-INS, SHALL BE NON-DESTRUCTIVELY INSPECTED FOR 100% OF CIRCUMFERENCE TO ACCEPTABLE CRITERIA OF WELD PROCEDURE (CSA), AND ALL RECORDS MAINTAINED.
3. ALL JOINT COATINGS SHALL BE PRE-HEATED, SANDBLASTED TO SSPC-10 AND COATED WITH ABRASION RESISTANT EPOXY.
4. JOINTS SHALL BE HOLIDAY TESTED BEFORE LOWERING AND REPAIRS UNDERTAKEN AND RE-INSPECTED.
5. PREBUILT SECTION SHALL BE HYDROSTATICALLY TESTED PRIOR TO INSTALLATION BY OPEN CUT.
6. SILT FENCING IS A SUITABLE SUBSTITUTE FOR A SOIL BERM.
7. CONDUCTIVITY TESTING SHALL BE COMPLETED POST INSTALLATION.

HADD DISTURBANCE

(A) AREA - INSTREAM = 9927 m^2
(B) AREA - RIPARIAN = 5425 m^2

CHINOOK ENGINEERING	RO	ISSUED FOR COMMENT		DAH	DB	DAE	10-03-04
BY	No.	REVISION		DRAWN	DESIGNED	CHECKED	DATE(YY-MM-DD)
PREVIOUS DR. NO.-			SAP ID:		MICROFILMED		SCALE- AS SHOWN

Terasen Gas

ENGINEER SEAL

168.3mm TP - MUSKWA PIPELINE

PRELIMINARY DESIGN
MUSKWA RIVER AT Kp 17+300
OPEN CUT PLAN AND PROFILE

DRAWING NUMBER 32004-P-000-1001-R0

Attachment 21.1

PRELIMINARY PROJECT SCHEDULE

Project: **Terasen Gas - Muskwa River HDD**

Spread: **Live Line Lowering**

Length: **340 m**

Resource		MONTH	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
		DURATION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER
		Work Days																					
DESIGN																							
	Preliminary Design	10d																					
	Fish & Fish Habitat Assessment	20d																					
	Fisheries Application	5d																					
	Final Design	15d																					
PROCUREMENT																							
	Material RFQ	15d																					
	Material PO	20d																					
	Line Pipe Lead Times to Delivery	240d																					
	Valve Lead Times to Delivery	180d																					
	Construction Contact - Bid Package	15d																					
	Construction Contact - Bidding	30d																					
	Construction Contact - Award	1d																					
REGULATORY & STAKEHOLDER CONSULTATIONS																							
	Fort Nelson IR consultations	30d																					
	OGC Permit Application	15d																					
	DFO Application & Letter of Authorization	60d																					
	BC FrontCounter Application (land & timber)	60d																					
CONSTRUCTION																							
	Construction	40d																					
COMMISSION																							
	Hot Tie-ins & Gasification	3d																					
OWNER ACCEPTANCE																							
	Project Close-out & Owner Acceptance	15d																					

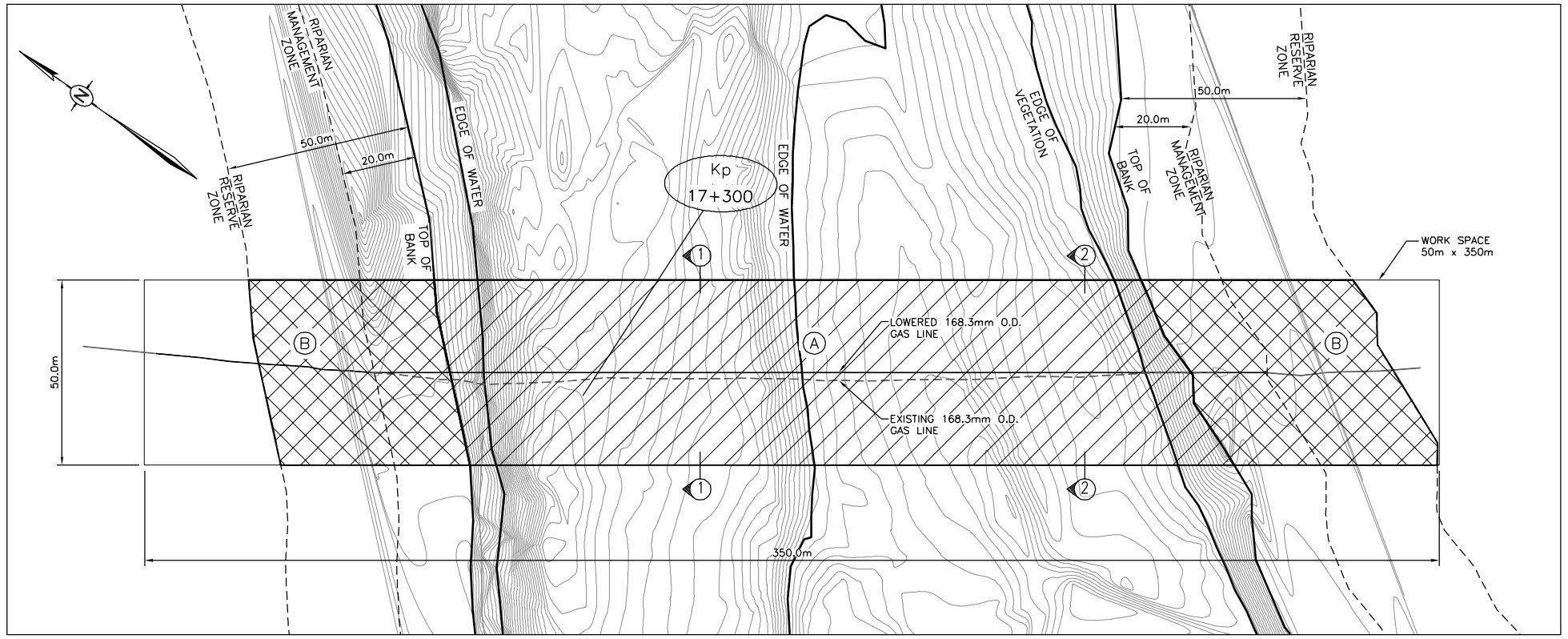
	PROJECT	Muskwa River - Line Lowering		LENGTH (m)	340
	YEAR	2009		DIA. (mm)	168
	FROM	0+000		W.T. (mm)	11.00
	TO	0+340		S.M.Y.S.(grade)	290
				MAOP. (kPa)	7,960

SERVICES

CODE NO.	DESCRIPTION	COMMENTS	UNIT PRICE	NO, OF UNITS	CONSTRUCTION DOLLARS	REFERENCE
401	Base Lay Contract: Clearing		$ 250.37	340	$ 85,125	Resource Worksheet
402	Base Lay Contract: Grading		$ 236.55	340	$ 80,428	Resource Worksheet
403	Base Lay Contract: Stringing		$ 74.18	340	$ 25,222	Resource Worksheet
404	Base Lay Contract: Ditching		$ 368.36	340	$ 125,241	Resource Worksheet
405	Base Lay Contract: Lowering		$ 970.18	340	$ 329,860	Resource Worksheet
406	Base Lay Contract: Back Fill		$ 464.44	340	$ 157,911	Resource Worksheet
407	Base Lay Contract: Hydrotesting		$ 27.82	340	$ 9,458	Resource Worksheet
408	Sub Contract: Hydrovac		$ 19.52		$ -	Superior City Quote
409	Sub Contract: NDT - Ultrasonic line for condition assessment		$ 6.29	340	$ 2,139	Cantech Quote
410			$ -		$ -	
411			$ -		$ -	
412			$ -		$ -	
413			$ -		$ -	
414			$ -		$ -	
415	Unit Price Rate: Coating Repairs		$ 250.00	75	$ 18,750	Estimate
416	Unit Price Rate: Traffic Control, Non-Permanent		$ -		$ -	
417	Unit Price Rate: Weld Destructive Testing		$ -		$ -	
418			$ -		$ -	
419	Unit Price Rate: Installation of electrical test leads		$ 1,200.00	2	$ 2,400	Estimate
420	Unit Price Rate: ROW Seeding		$ 8.00	1,000	$ 8,000	Estimate
421	Unit Price Rate: 3/4 Minus Import		$ 135.00	10	$ 1,350	Blue Canyon
422	Unit Price Rate: Pipeline Sand Padding		$ 97.50	54	$ 5,265	Blue Canyon
423	Unit Price Rate: Road Aggregate Import		$ 105.00	420	$ 44,100	Blue Canyon
424	Unit Price Rate: Rip Rap D50 Import		$ 150.00	900	$ 135,000	Blue Canyon
425	Unit Price Rate: Air drying pipeline		$ 25,000.00		$ -	Estimate
426	Unit Price Rate: Installation of warning signs		$ 150.00	6	$ 900	Estimate
427	Unit Price Rate: Installation of Ditch Plugs		$ 5,000.00	2	$ 10,000	Estimate
428	Mark ups: Material		$ -		$ -	
429	Mark ups: Third Party	Incl in Sub Cost	$ -		$ -	
430	Misc. Expenses		$ -		$ -	
	TOTAL CONSTRUCTION				**$ 1,041,149**	
					$ 3,062	**/ meter Construction**
	ENGINEERING & INSPECTION					
101	Design Engineering (EPCM)		$ 30,000	1	$ 30,000	Task Sheet
102	Land Services & Permitting		$ 10,000	1	$ 10,000	Task Sheet
103	Geotechnical Investigation (boreholes)		$ -	1	$ -	Estimate
104	Surveys		$ 5.43	340	$ 1,846	Bennet Land Survey
105	Environmental Field Inspection				$ -	Estimate
106	Field Inspection & Pipeline QA		$ 3,523	40	$ 140,910	Resource Worksheet
108	Gauge Pigging and Biocide Run		$ -	-	$ -	Estimate
109	Shop Inspections		$ -	-	$ -	Estimate
111	Mill Inspections		$ 15,000	-	$ -	Estimate
112	HADD Environmental Remediation (2:1 ratio for disturbance)		$ 10	30,700	$ 307,000	Estimate
	TOTAL ENGINEERING & INSPECTION				**$ 489,756**	
	COMMISSIONING					
501	Engineering Commissioning Support		$ 1,500	-	$ -	Resource Worksheet
502	Terasen Gas Transmission Crew for Hot Tie-ins (incl. above)		$ 12,855	-	$ -	Resource Worksheet
503	Operating Procedures					
504	Training					
	TOTAL COMMISSIONING				**$ -**	

MATERIALS

CODE NO.	DESCRIPTION	MATERIALS QUANTITY		UNIT PRICE		MATERIAL DOLLARS	WBS
301	Line Pipe (Z662) w/ DPS Coating	0	m	$ 140		$ -	Quote
303	Line Pipe Coating - Concrete overcoat	0	m	$ 30		$ -	Quote
303	Joint Coatings - Heat Shrink Sleeves	0	ea	$ 25		$ -	Quote
303	Joint Coatings - HDD Heat Shrink Sleeves	0	ea	$ 53		$ -	Quote
311	Barge Rental	40	d	$ 3,500		$ 140,000	Cooper Barging Service
329	Buoyancy Control	38	ea	$ 500		$ 18,750	
330	Valve Station Materials	0		$ -		$ -	
343	Pig Barrel Materials	0		$ -		$ -	
344	Induction Bends	0		$ -		$ -	
345	Corrosion Inhibition Chemicals	0		$ -		$ -	
350	Freight & Hauling	0		$ -		$ -	
399	Misc. Equipment	0		$ -		$ -	
	SUB-TOTAL					**$ 158,750**	
	PROVINCIAL SALES TAX					**$ 11,113**	
	TOTAL MATERIALS					**$ 169,863**	
					sub-total	**$ 1,701,000**	
					CONTINGENCY (15%)	**$ 255,150**	
					GRAND TOTAL	**$ 1,956,150**	
					per m	**$ 5,753**	**/M**



PLAN
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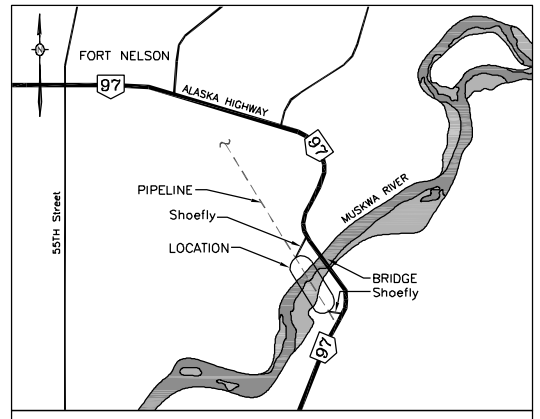


LOCATION PLAN
SCALE: N.T.S.

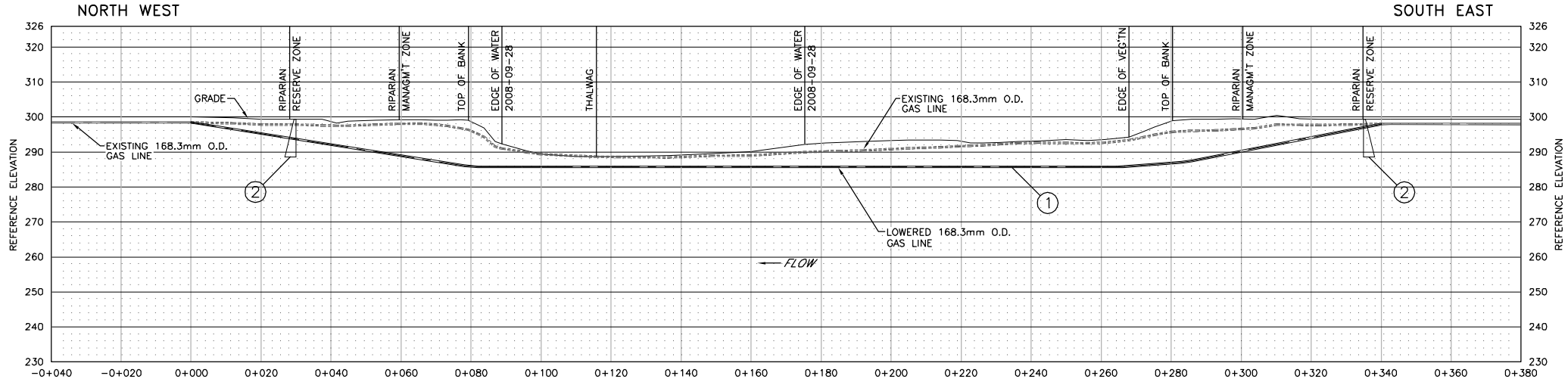
GENERAL LOCATION

KILOMETER POST:	17+300
NTS LAND LOCATION:	B-043-B / 094-J-15
UTM ZONE:	10N NAD83, N6516320.243, E519639.591

MATERIAL LIST

ITEM	QTY.	DESCRIPTION	REF. DWG.
1	340m	168.3mm X 11mm W.T., GR 241, API5L	---
		EXISTING PIPE INSTALLED 1974	
2	2	DITCH PLUGS	

CLASS LOCATION: 3
OVERALL SAFETY FACTOR: 56%
M.O.P. 7960 kPa



PROFILE

DESIGN NOTES

1. CROSSING SECTION - TEST PRESSURE
   MINIMUM = 11 144 kPa
   MAXIMUM = 15 000 kPa
   DURATION = 24 HOURS
2. DESIGN TEMPERATURE - M45C.

CONSTRUCTION NOTES

1. MINIMUM DEPTH OF COVER: 1.2m (GENERAL) AND 2.5m (RIVER & FLOOD PLAIN).
2. ALL WELDS, INCLUDING TIE-INS, SHALL BE NON-DESTRUCTIVELY INSPECTED FOR 100% OF CIRCUMFERENCE TO ACCEPTABLE CRITERIA OF WELD PROCEDURE (CSA), AND ALL RECORDS MAINTAINED.
3. ALL JOINT COATINGS SHALL BE PRE-HEATED, SANDBLASTED TO SSPC-10 AND COATED WITH ABRASION RESISTANT EPOXY.
4. JOINTS SHALL BE HOLIDAY TESTED BEFORE LOWERING AND REPAIRS UNDERTAKEN AND RE-INSPECTED.
5. PREBUILT SECTION SHALL BE HYDROSTATICALLY TESTED PRIOR TO INSTALLATION BY OPEN CUT.
6. SILT FENCING IS A SUITABLE SUBSTITUTE FOR A SOIL BERM.
7. CONDUCTIVITY TESTING SHALL BE COMPLETED POST INSTALLATION.

HADD DISTURBANCE

(A) AREA - INSTREAM = 9927 m^2
(B) AREA - RIPARIAN = 5425 m^2

CHINOOK ENGINEERING	RO	ISSUED FOR COMMENT		DAH	DB	DAE	10-03-04
BY	No.	REVISION		DRAWN	DESIGNED	CHECKED	DATE(YY-MM-DD)
PREVIOUS DR. NO.-			SAP ID:		MICROFILMED		SCALE- AS SHOWN

Terasen Gas

ENGINEER SEAL

168.3mm TP - MUSKWA PIPELINE

PRELIMINARY DESIGN
MUSKWA RIVER AT Kp 17+300
LOWERING PLAN AND PROFILE

DRAWING NUMBER 32004-P-000-1002-R0

Attachment 21.1

PRELIMINARY PROJECT SCHEDULE

Project: **Terasen Gas - Muskwa River HDD**

Spread: **Bridge Crossing & Station Upgrades**

Length: **810 m**

		MONTH	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Resource		DURATION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH
		Work Days															
DESIGN																	
	Preliminary Design	20d															
	-	-															
	-	-															
	Final Design	30d															
PROCUREMENT																	
	Material RFQ	15d															
	Material PO	20d															
	Line Pipe Lead Times to Delivery	240d															
	Valve Lead Times to Delivery	180d															
	Construction Contact - Bid Package	15d															
	Construction Contact - Bidding	30d															
	Construction Contact - Award	1d															
REGULATORY & STAKEHOLDER CONSULTATIONS																	
	Fort Nelson IR consultations	60d															
	OGC Permit Application	15d															
	-	-															
	BC FrontCounter Application (land & timber)	60d															
CONSTRUCTION																	
	Construction	48d															
COMMISSION																	
	Hot Tie-ins & Gasification	3d															
OWNER ACCEPTANCE																	
	Project Close-out & Owner Acceptance	20d															

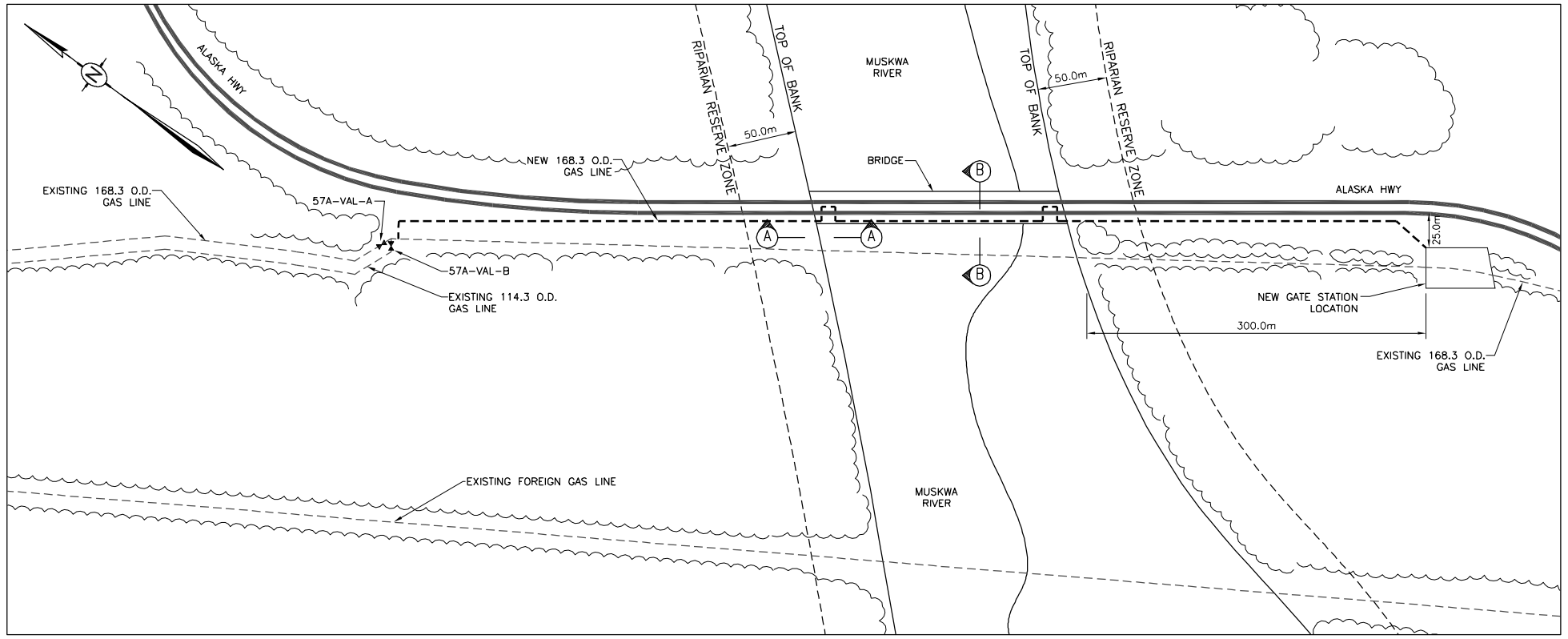
	PROJECT	Muskwa River - Bridge Crossing & Station	LENGTH (m)	750
	YEAR	2009	DIA. (mm)	168
	FROM	0+000	W.T. (mm)	11.00
	TO	0+750	S.M.Y.S.(grade)	290
			MAOP. (kPa)	7,960

SERVICES

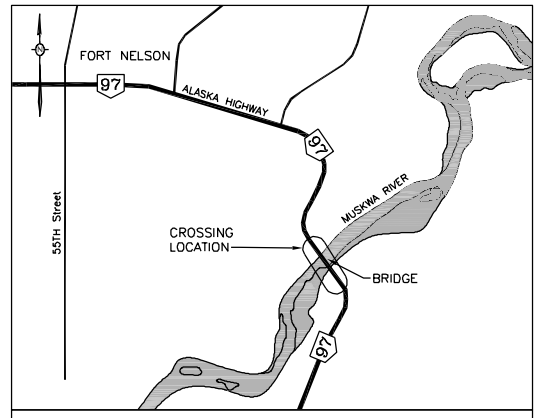
CODE NO.	DESCRIPTION	COMMENTS	UNIT PRICE	NO, OF UNITS	CONSTRUCTION DOLLARS	REFERENCE
401	PIPELINE Base Lay Contract: Clearing		$ 82.20	810	$ 66,579	Resource Worksheet
402	PIPELINE Base Lay Contract: Grading		$ 145.99	810	$ 118,250	Resource Worksheet
403	PIPELINE Base Lay Contract: Stringing		$ 94.54	810	$ 76,578	Resource Worksheet
404	PIPELINE Base Lay Contract: Ditching		$ 67.43	810	$ 54,621	Resource Worksheet
405	PIPELINE Base Lay Contract: Welding		$ 376.56	810	$ 305,013	Resource Worksheet
406	PIPELINE Base Lay Contract: Back Fill		$ 117.97	810	$ 95,552	Resource Worksheet
407	PIPELINE Base Lay Contract: Hydrotesting		$ 50.23	810	$ 40,687	Resource Worksheet
408	Sub Contract: Hydrovac		$ -		$ -	Superior City Quote
409	Sub Contract: NDT		$ 21.15	810	$ 17,132	Cantech Quote
410	STATION Fabrication		$ 101,148	1	$ 101,148	Resource Worksheet
411	STATION Construction Installation		$ 186,907	1	$ 186,907	Resource Worksheet
412	STATION Existing Decommission and Salvage		$ 33,223	1	$ 33,223	Resource Worksheet
413	BRIDGE - Mobilization, Scafolding & Pickers		$ 66,576	1	$ 66,576	Resource Worksheet
414	BRIDGE - Structural Steel Supports		$ 118,539	1	$ 118,539	Resource Worksheet
415	Unit Price Rate: Coating Repairs		$ 50.00	75	$ 3,750	Estimate
416	Unit Price Rate: Traffic Control, Non-Permanent		$ -		$ -	Estimate
417	Unit Price Rate: Weld Destructive Testing		$ 7,000.00		$ -	Estimate
418			$ -		$ -	
419	Unit Price Rate: Installation of electrical test leads		$ 1,200.00	4	$ 4,800	Line List
420	Unit Price Rate: ROW Seeding		$ 8.00	810	$ 6,480	Line List
421	Unit Price Rate: 3/4 Minus Import		$ 135.00	250	$ 33,750	Blue Canyon
422	Unit Price Rate: Pipeline Sand Padding		$ 97.50	250	$ 24,375	Blue Canyon
423	Unit Price Rate: Road Aggregate Import		$ 105.00		$ -	Blue Canyon
424	Unit Price Rate: Rip Rap D50 Import		$ 150.00		$ -	Blue Canyon
425	Unit Price Rate: Air drying pipeline		$ 25,000.00		$ -	
426	Unit Price Rate: Installation of warning signs		$ 150.00	6	$ 900	Line List
427	Unit Price Rate: Installation of Ditch Plugs		$ -		$ -	
428	Mark ups: Material		$ -		$ -	
429	Mark ups: Third Party	Incl in Sub Cost	$ -		$ -	
430	Misc. Expenses		$ -		$ -	
	TOTAL CONSTRUCTION				**$ 1,354,861**	
	ENGINEERING & INSPECTION					
101	Design Engineering (EPCM)		$ 60,000	1	$ 60,000	Task Sheet
102	Land Services & Permitting		$ 10,000	1	$ 10,000	Task Sheet
103	Geotechnical Investigation (boreholes)		$ -		$ -	Estimate
104	Surveys		$ 4.97	810	$ 4,026	Bennet Land Survey
105	Environmental Field Inspection				$ -	Estimate
106	Field Inspection & Pipeline QA		$ 2,927	48	$ 140,495	Resource Worksheet
108	Gauge Pigging and Biocide Run		$ -	-	$ -	Estimate
109	Engineering Support for Construction		$ 1,500	10	$ 15,000	Estimate
111	Shop Inspections		$ -	-	$ -	Estimate
112	Mill Inspections		$ 15,000	-	$ -	Estimate
	TOTAL ENGINEERING & INSPECTION				**$ 229,521**	
	COMMISSIONING					
501	Engineering Commissioning Support		$ 1,500	5	$ 7,500	Resource Worksheet
502	Terasen Gas Transmission Crew for Hot Tie-ins		$ 12,855	3	$ 38,565	Resource Worksheet
503	Operating Procedures					
504	Training					
	TOTAL COMMISSIONING				**$ 46,065**	

MATERIALS

CODE NO.	DESCRIPTION	MATERIALS QUANTITY		UNIT PRICE		MATERIAL DOLLARS	WBS
301	Line Pipe (Z662)	810	m	$ 110		$ 89,100	Quote
303	Line Pipe Coating - DPS	0		$ 30		$ -	Quote
303	Joint Coatings - Heat Shrink Sleeves	68	ea	$ 25		$ 1,657	Quote
303	Joint Coatings - HDD Heat Shrink Sleeves	0		$ 53		$ -	Quote
311	Cathodic Protection	0		$ -	-	$ -	
329	Buoyancy Control	0		$ -	-	$ -	
330	Valve Station Materials	1	ea	$ 150,000		$ 150,000	
343	Telemetry Materials	1	ea	$ 35,000		$ 35,000	
344	Induction Bends	0		$ -		$ -	
345	Corrosion Inhibition Chemicals	0		$ -		$ -	
350	Freight & Hauling	0		$ -		$ -	
399	Misc. Equipment	0		$ -		$ -	
	SUB-TOTAL					**$ 275,757**	
	PROVINCIAL SALES TAX					**$ 19,303**	
	TOTAL MATERIALS					**$ 295,060**	
					sub-total	**$ 1,926,000**	
					CONTINGENCY (15%)	**$ 288,900**	
					GRAND TOTAL	**$ 2,214,900**	
					per m	**$ 2,953**	**/M**



PLAN
SCALE: N.T.S.



LOCATION PLAN
SCALE: N.T.S.

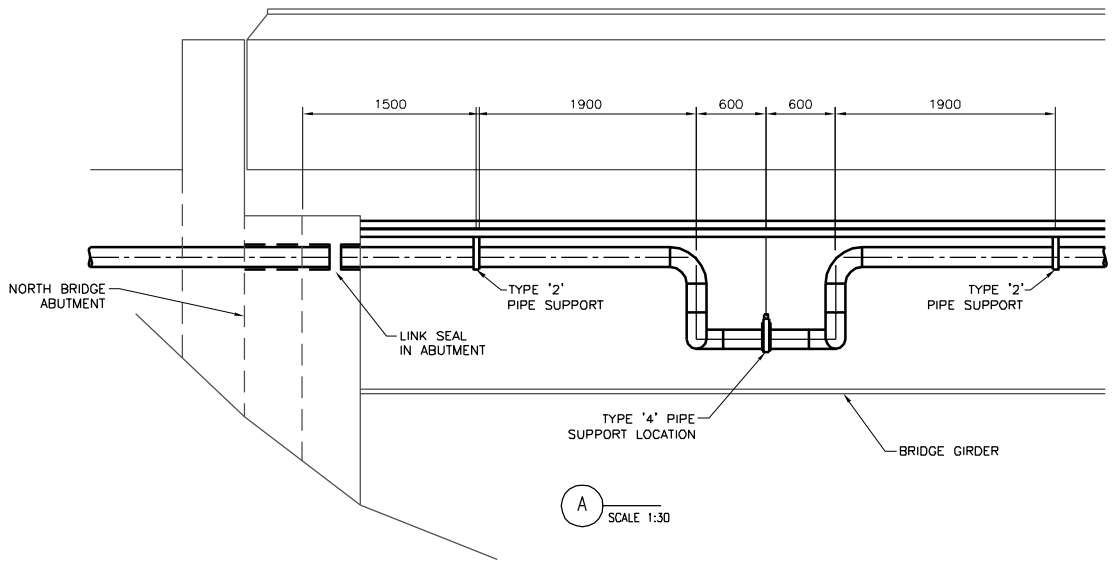
GENERAL LOCATION

KILOMETER POST:	17+300
NTS LAND LOCATION:	B-043-B / 094-J-15
UTM ZONE:	10N NAD83, N6516320.243, E519639.591

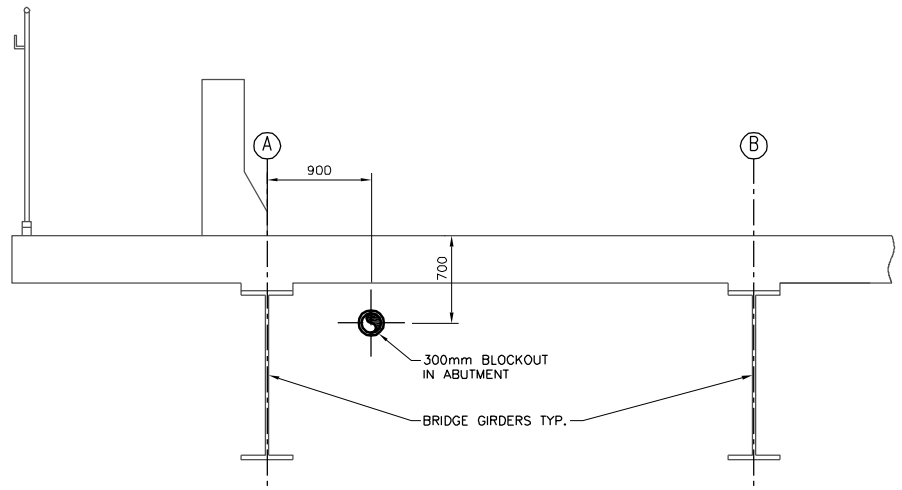
MATERIAL LIST

ITEM	QTY.	DESCRIPTION	REF. DWG.
1	810m	168.3mm X 7.11mm W.T., GR 290, CSA Z245.1,	---
		CAT II, DPS COATING, DBL RANDOM, ERW	

CLASS LOCATION: 3
OVERALL SAFETY FACTOR: 56%
M.O.P. 2068 kPa



A SCALE 1:30



B SCALE 1:30

DESIGN NOTES

1. CROSSING SECTION – TEST PRESSURE
   MINIMUM = 3 000 kPa
   MAXIMUM = 5 000 kPa
   DURATION = 24 HOURS
2. DESIGN TEMPERATURE – M45C.

CONSTRUCTION NOTES

1. MINIMUM DEPTH OF COVER: 1.2m (GENERAL).
2. ALL WELDS, INCLUDING TIE-INS, SHALL BE NON-DESTRUCTIVELY INSPECTED FOR 100% OF CIRCUMFERENCE TO ACCEPTABLE CRITERIA OF WELD PROCEDURE (CSA), AND ALL RECORDS MAINTAINED.
3. ALL JOINT COATINGS SHALL BE PRE-HEATED, SANDBLASTED TO SSPC-10 AND COATED WITH ABRASION RESISTANT EPOXY.
4. JOINTS SHALL BE HOLIDAY TESTED BEFORE LOWERING AND REPAIRS UNDERTAKEN AND RE-INSPECTED.
5. PREBUILT SECTION SHALL BE HYDROSTATICALLY TESTED PRIOR TO PULLING UNDER BRIDGE DECK.
6. SILT FENCING IS A SUITABLE SUBSTITUTE FOR A SOIL BERM.
7. CONDUCTIVITY TESTING SHALL BE COMPLETED POST INSTALLATION.

CHINOOK ENGINEERING	R0	ISSUED FOR COMMENT	DAH	DB	DAE	10-03-04
BY	No.	REVISION	DRAWN	DESIGNED	CHECKED	DATE(YY-MM-DD)
PREVIOUS DR. NO.-		SAP ID:		MICROFILMED		SCALE- AS SHOWN

Terasen Gas

ENGINEER SEAL

168.3mm TP – MUSKWA PIPELINE

PRELIMINARY DESIGN
BRIDGE CROSSING OF THE
MUSKWA RIVER AT Kp 17+300
PLAN AND PROFILE

DRAWING NUMBER 32004-P-000-1003-R0

Attachment 21.1

		PROJECT	Muskwa River - Cost Comparison	LENGTH (m)	-	February 11, 2010
		YEAR	2009	DIA. (mm)	168	
		FROM	-	W.T. (mm)	11.00	
		TO	-	S.M.Y.S.(grade)	290	
				MAOP. (kPa)	7,960	

COST COMPARISON

OPTION	DESCRIPTION	AACE CLASS 4 ESTIMATE Lower Bound -30%	MEAN	Upper Bound +50%	SELECTION	COMMENT
1	HDD - Peak to Peak	$ 1,143,905	1,634,150	$ 2,451,225	1st CONTINGENCY	Contingent on Geotechnical Results
1	HDD - Low to High	$ 1,045,695	1,493,850	$ 2,240,775	RECOMMENDED ACTION	Contingent on Geotechnical Results
2	Open Cut - No isolation	$ 1,287,195	1,838,850	$ 2,758,275	3rd CONTINGENCY	Contingent on DFO authorization
3	Pipe Live Lowering	$ 1,369,305	1,956,150	$ 2,934,225	*NOT RECOMMENDED*	Unknown asset condition & high risk activity
4	Station Relocation & Bridge Crossing	$ 1,550,430	2,214,900	$ 3,322,350	2nd CONTINGENCY	Contingency on DPW

MACRO RISK EVALUATION

OPTION	DESCRIPTION	RISK CONSTRUCTIBILITY	SCHEDULE	ENVIRONMENTAL	OVERALL RISK FACTOR	COMMENT
1	HDD - Peak to Peak	1.05	1.05	1.0	1.10	Risk of Construction Failure, based on geotechnical.
1	HDD - Low to High	1.03	1.05	1.0	1.08	Risk of Construction Failure, based on geotechnical.
2	Open Cut - No isolation	1.0	1.05	1.05	1.10	High Environmental Impact
3	Pipe Live Lowering	1.05	1.05	1.05	1.16	High Environmental Impact
4	Station Relocation & Bridge Crossing	1.05	0.95	0.95	0.95	High Safety Risks during Construction

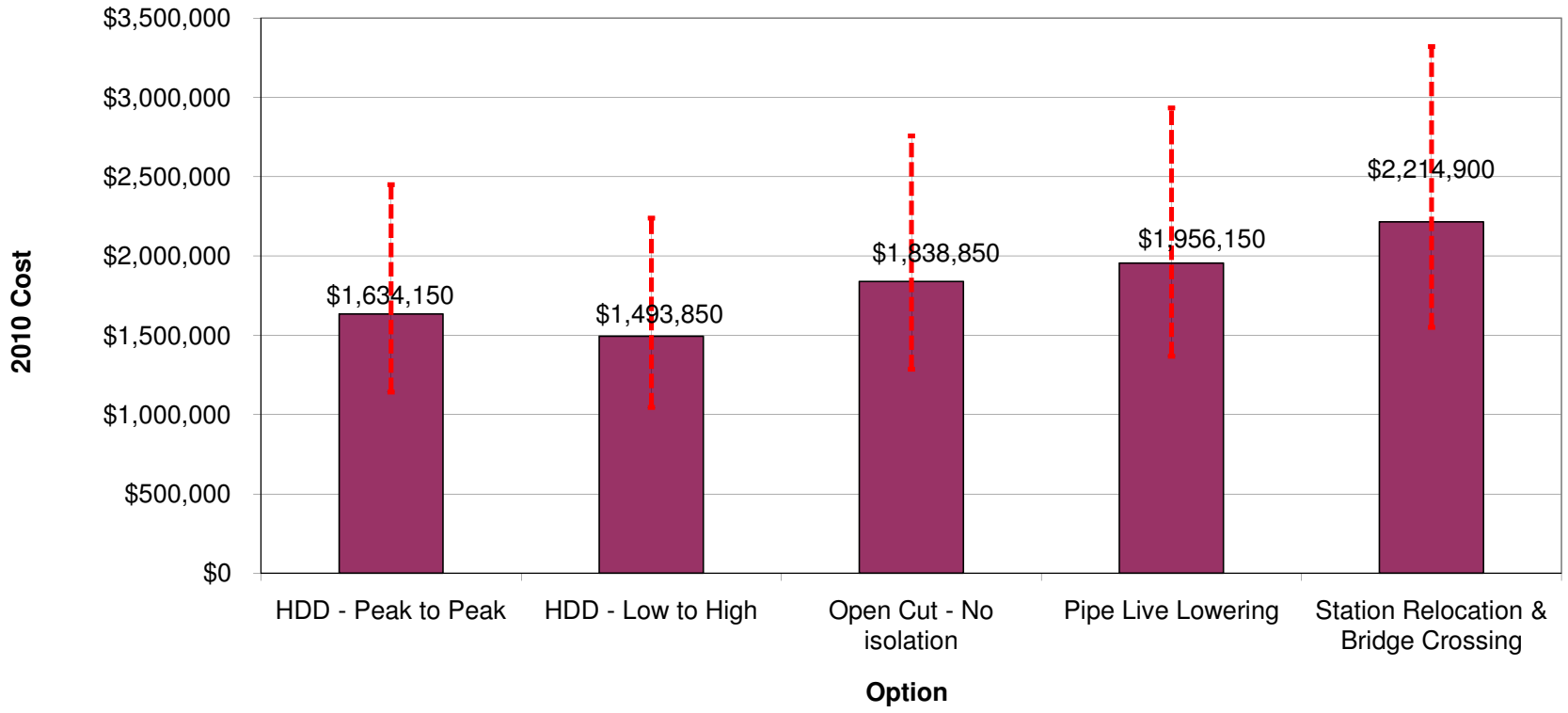
RISK FACTORS	PROBABILITY	CONSEQUENCE
LOW	1.0	0.95
MODERATE	1.0	1.00
HIGH	1.0	1.05

NOTE: Analysis assumes equal probability of all events.

RISK MULTIPLIED COST

OPTION	DESCRIPTION	AACE CLASS 4 ESTIMATE Lower Bound -30%	MEAN	Upper Bound +50%		
1	HDD - Peak to Peak	$ 1,261,155	$ 1,801,650	$ 2,702,476		
1	HDD - Low to High	$ 1,125,429	$ 1,607,756	$ 2,411,634		
2	Open Cut - No isolation	$ 1,419,132	$ 2,027,332	$ 3,040,998		
3	Pipe Live Lowering	$ 1,585,142	$ 2,264,488	$ 3,396,732		
4	Station Relocation & Bridge Crossing	$ 1,469,226	$ 2,098,895	$ 3,148,342		

Project Option Base Cost Comparisons



Attachment 22.1

		PROJECT	Muskwa River - D50:300mm Rip Rap	LENGTH (m)	240
		YEAR	2009	DIA. (mm)	168
		FROM	0+000	W.T. (mm)	11.00
		TO	0+240	S.M.Y.S.(grade)	290
				MAOP. (kPa)	7,960

SERVICES

CODE NO.	DESCRIPTION	COMMENTS		UNIT PRICE	NO, OF UNITS	CONSTRUCTION DOLLARS	REFERENCE
401	Base Lay Contract: Mobilization	lump	$	70,856.11	1	$ 70,856	Resource Worksheet
402	Base Lay Contract: Clearing & Grading		$	259.33	240	$ 62,238	Resource Worksheet
403	Base Lay Contract: Instream Isolation, Recoating & Backfill		$	847.56	240	$ 203,413	Resource Worksheet
404	Base Lay Contract: Rip Rap Install		$	858.51	240	$ 206,043	Resource Worksheet
405	Base Lay Contract: Site Restortation		$	280.05	240	$ 67,212	Resource Worksheet
406	Base Lay Contract: Demobilize	lump	$	33,883.58	1	$ 33,884	Resource Worksheet
407			$	-		$ -	
408			$	-		$ -	
409	Sub Contract: Coating Inspection - ECDA	lump	$	18,900.00	1	$ 18,900	Resource Worksheet
410			$	-		$ -	
411			$	-		$ -	
412			$	-		$ -	
413			$	-		$ -	
414			$	-		$ -	
415	Unit Price Rate: Coating Repairs	m2	$	50.00	50	$ 2,500	Estimate
416	Unit Price Rate: Traffic Control, Non-Permanent		$	-		$ -	
417	Unit Price Rate: Weld Destructive Testing		$	-		$ -	
418			$	-		$ -	
419	Unit Price Rate: Installation of electrical test leads	ea	$	1,200.00		$ -	
420	Unit Price Rate: ROW Seeding		$	8.00	500	$ 4,000	Estimate
421	Unit Price Rate: 3/4 Minus Import	m3	$	135.00	0	$ -	Blue Canyon
422	Unit Price Rate: Pipeline Sand Padding	m3	$	97.50	100	$ 9,750	Blue Canyon
423	Unit Price Rate: Pit Run	m3	$	105.00	170	$ 17,850	Blue Canyon
424	Unit Price Rate: Rip Rap D50:300mm	m3	$	34.00	8,973	$ 305,075	Blue Canyon
425			$	-		$ -	
426	Unit Price Rate: Installation of warning signs	ea	$	150.00	4	$ 600	Estimate
427	Unit Price Rate: Installation of Ditch Plugs	ea	$	-		$ -	
428	Mark ups: Material		$	-		$ -	
429	Mark ups: Third Party	Incl in Sub Cost	$	-		$ -	
430	Misc. Expenses		$	-		$ -	
	TOTAL CONSTRUCTION					**$ 1,002,321**	
						$ 4,176	**/ meter Construction**
	ENGINEERING & INSPECTION						
101	Design Engineering (EPCM)		$	10,000	1	$ 10,000	Task Sheet
102	Land Services & Permitting		$	12,500	1	$ 12,500	Task Sheet
103	Hydrological Design (BCG Engineering)		$	10,000	1	$ 10,000	Estimate
104	Surveys		$	15.53	240	$ 3,728	Bennet Land Survey
105	Environmental Field Inspection					$ -	
106	Field Inspection & Pipeline QA	per day	$	2,520	30	$ 75,600	Resource Worksheet
108	Gauge Pigging and Biocide Run		$	-		$ -	
109	Shop Inspections		$	-		$ -	
111	Mill Inspections		$	-		$ -	
112	HADD Environmental Remediation (2:1 ratio for disturbance)		$	10	30,000	$ 300,000	Estimate
	TOTAL ENGINEERING & INSPECTION					**$ 411,828**	
	COMMISSIONING						
501	Engineering Site Supervision		$	1,500	5	$ 7,500	Resource Worksheet
502	Terasen Gas Transmission Crew for Hot Tie-ins (incl. above)						
503	Operating Procedures						
504	Training						
	TOTAL COMMISSIONING					**$ 7,500**	

MATERIALS

CODE NO.	DESCRIPTION	MATERIALS QUANTITY		UNIT PRICE		MATERIAL DOLLARS	WBS
301	Armourflex' Cabled Concrete Mats		m2	$ -		$ -	
303				$ -		$ -	
303	Coatings Materials	1	ea	$ 5,000		$ 5,000	Estimate
303	Geotextile	11,000	m2	$ 5		$ 55,000	Estimate
311				$ -		$ -	
329				$ -		$ -	
330				$ -		$ -	
343				$ -		$ -	
344				$ -		$ -	
345				$ -		$ -	
350	Freight & Hauling (1 hour return trip to Blue Canyon Pit)	1,196	loads	$ 165		$ 197,402	Quote
399	Misc. Equipment			$ -		$ -	
	SUB-TOTAL					**$ 257,402**	
	PROVINCIAL SALES TAX					**$ 18,018**	
	TOTAL MATERIALS					**$ 275,420**	

sub-total	**$**	**1,697,000**
CONTINGENCY (15%)	**$**	**254,550**
GRAND TOTAL	**$**	**1,951,550**
per m	**$**	**8,131 /M**

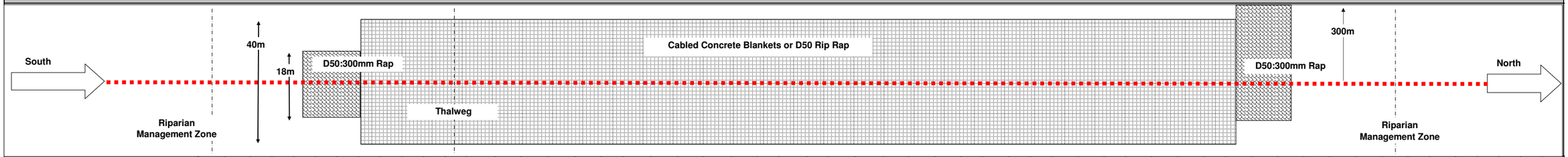
		PROJECT	Muskwa River - Cabled Concrete Rip Rap	LENGTH (m)	240
		YEAR	2009	DIA. (mm)	168
		FROM	0+000	W.T. (mm)	11.00
		TO	0+240	S.M.Y.S.(grade)	290
				MAOP. (kPa)	7,960

SERVICES

CODE NO.	DESCRIPTION	COMMENTS		UNIT PRICE	NO, OF UNITS	CONSTRUCTION DOLLARS	REFERENCE
401	Base Lay Contract: Mobilization	lump	$	70,856.11	1	$ 70,856	Resource Worksheet
402	Base Lay Contract: Clearing & Grading		$	281.82	240	$ 67,638	Resource Worksheet
403	Base Lay Contract: Instream Isolation, Recoating & Backfill		$	847.56	240	$ 203,413	Resource Worksheet
404	Base Lay Contract: Rip Rap Install		$	345.40	240	$ 82,895	Resource Worksheet
405	Base Lay Contract: Site Restortation		$	280.05	240	$ 67,212	Resource Worksheet
406	Base Lay Contract: Demobilize	lump	$	33,883.58	1	$ 33,884	Resource Worksheet
407			$	-		$ -	
408			$	-		$ -	
409	Sub Contract: Coating Inspection - ECDA	lump	$	18,900.00	1	$ 18,900	Resource Worksheet
410			$	-		$ -	
411			$	-		$ -	
412			$	-		$ -	
413			$	-		$ -	
414			$	-		$ -	
415	Unit Price Rate: Coating Repairs	m2	$	50.00	50	$ 2,500	Estimate
416	Unit Price Rate: Traffic Control, Non-Permanent		$	-		$ -	
417	Unit Price Rate: Weld Destructive Testing		$	-		$ -	
418			$	-		$ -	
419	Unit Price Rate: Installation of electrical test leads	ea	$	-		$ -	
420	Unit Price Rate: ROW Seeding		$	8.00	1,000	$ 8,000	Estimate
421	Unit Price Rate: 3/4 Minus Import	m3	$	135.00	0	$ -	Blue Canyon
422	Unit Price Rate: Pipeline Sand Padding	m3	$	97.50	100	$ 9,750	Blue Canyon
423	Unit Price Rate: Pit Run	m3	$	105.00	170	$ 17,850	Blue Canyon
424	Unit Price Rate: Rip Rap D50:300mm	m3	$	150.00	108	$ 16,200	Blue Canyon
425			$	-		$ -	
426	Unit Price Rate: Installation of warning signs	ea	$	150.00	4	$ 600	Estimate
427	Unit Price Rate: Installation of Ditch Plugs	ea	$	-		$ -	
428	Mark ups: Material		$	-		$ -	
429	Mark ups: Third Party	Incl in Sub Cost	$	-		$ -	
430	Misc. Expenses		$	-		$ -	
	TOTAL CONSTRUCTION					**$ 599,698**	
						$ 2,499	**/ meter Construction**
	ENGINEERING & INSPECTION						
101	Design Engineering (EPCM)		$	10,000	1	$ 10,000	Task Sheet
102	Land Services & Permitting		$	12,500	1	$ 12,500	Estimate
103	Hydrological Design (BCG Engineering)		$	10,000	1	$ 10,000	Estimate
104	Surveys		$	15.53	240	$ 3,728	Bennet Land Survey
105	Environmental Field Inspection		$	-		$ -	
106	Field Inspection & Pipeline QA	per day	$	2,520	30	$ 75,600	Resource Worksheet
108	Gauge Pigging and Biocide Run		$	-		$ -	
109	Shop Inspections		$	-		$ -	
111	Mill Inspections		$	-		$ -	
112	HADD Environmental Remediation (2:1 ratio for disturbance)		$	10	30,000	$ 300,000	Estimate
	TOTAL ENGINEERING & INSPECTION					**$ 411,828**	
	COMMISSIONING						
501	Engineering Site Supervision		$	1,500	5	$ 7,500	Resource Worksheet
502	Terasen Gas Transmission Crew for Hot Tie-ins (incl. above)						
503	Operating Procedures						
504	Training						
	TOTAL COMMISSIONING					**$ 7,500**	

MATERIALS

CODE NO.	DESCRIPTION	MATERIALS QUANTITY		UNIT PRICE		MATERIAL DOLLARS	WBS
301	'Armourflex' Cabled Concrete Mats (2m x 6m) - Instream	8,000	m2	$ 96		$ 768,000	Armourflex Quote
303	'Armourflex' Cabled Concrete Mats (2m x 6m) - Bank	3,000	m2	$ 96		$ 288,000	Armourflex Quote
303	Coatings Materials	1		$ 5,000		$ 5,000	Estimate
303	Geotextile	11,000	m2	$ 5		$ 55,000	Estimate
311				$ -		$ -	
329				$ -		$ -	
330				$ -		$ -	
343				$ -		$ -	
344				$ -		$ -	
345				$ -		$ -	
350	Freight & Hauling - Cabled Concrete (150 m2 / trailer)	73	loads	$ 4,500	per delivery	$ 330,000	Estimate
399	Misc. Equipment			$ -		$ -	
	SUB-TOTAL					**$ 1,446,000**	
	PROVINCIAL SALES TAX					**$ 101,220**	
	TOTAL MATERIALS					**$ 1,547,220**	
					sub-total	**$ 2,566,000**	
					CONTINGENCY (15%)	**$ 384,900**	
					GRAND TOTAL	**$ 2,950,900**	
					per m	**$ 12,295**	**/m**



Attachment 22.1

Macro-Level Construction Plan

MUSKWA RIVER - RIP RAP COST ESTIMATE

0+060 0+065 0+070 0+075 0+080 0+085 0+090 0+095 0+100 0+105 0+110 0+115 0+120 0+125 0+130 0+135 0+140 0+145 0+150 0+155 0+160 0+165 0+170 0+175 0+180 0+185 0+190 0+195 0+200 0+205 0+210 0+215 0+220 0+225 0+230 0+235 0+240 0+245 0+250 0+255 0+260 0+265 0+270 0+275 0+280 0+285 0+290 0+295 0+300 0+305 0+310 0+315 0+320 0+325 0+330 0+335

	Name	MUSKWA RIVER					
PIPELINE	Regulatory Jurisdiction	OIL & GAS COMMISSION					
	Nominal Pipeline Size	168.1mm x 11.0mm WT Gr. 290 Cat I ERW					
	Pipeline Control Points	RIPARIAN	TOP OF BANK	WATER EDGE	THALWEG	WATER EDGE	VEGN EDGE TOP OF BANK RIPARIAN
	Section Length	0.24 km					
	RIGHT-OF-WAY CONDITION	SILTY SOIL	GRAVEL RIVER SUBSTRATE	GRAVEL - SAND BAR	SILTY SOIL		
	SPREAD CREW	PRIME CONTRACTOR					
	RIP RAP TYPE	NONE	D50:300mm	CABLED CONCRETE OR D50:300mm	D50:300mm	NONE	
	RIP RAP WIDTH	NONE	18 m WIDE	40 m WIDE	300m to Bridge Abutment	NONE	
	AGGREGATE VOLUMES	NONE	RIP RAP 108m3	SAND: 100 m3 PIT RUN: 120 m3 RIP-RAP: 1920 m3	PIT RUN: 50 m3 RIP RAP: 2880 m3	RIP RAP: 1800 m3	NONE
	SPECIAL REQUIREMENTS	2% BENCHLAND	20% BANK SLOPE	RIVER GRADE	SANDBAR GRADE	20% BANK SLOPE	2% BENCHLAND
	LAND USE	CROWN LAND					
	COATING INSPECTION	NONE	ECDA	VISUAL INSPECTION & ECDA	ECDA	ECDA	NONE
CONTRACT	Tender Philosophy	LUMP SUM CONTRACT					
	Subcontract, Inspection	ECDA VENDOR					
	Field Duration	30 DAYS					

CROSS - SECTION OF RIP-RAP INSTALLATION

		PROJECT	Muskwa River - Cost Comparison	LENGTH (m)	-	April 19, 2010
		YEAR	2010	DIA. (mm)	168	
		FROM	-	W.T. (mm)	11.00	
		TO	-	S.M.Y.S.(grade)	290	
				MAOP. (kPa)	7,960	

COST COMPARISON

OPTION	DESCRIPTION	AACE CLASS 4 ESTIMATE Lower Bound -30%	MEAN	Upper Bound +50%	SELECTION	COMMENT
1	HDD - Peak to Peak	$ 1,143,905	1,634,150	$ 2,451,225	1st CONTINGENCY	Contingent on Geotechnical Results
1	HDD - Low to High	$ 1,045,695	1,493,850	$ 2,240,775	RECOMMENDED ACTION	Contingent on Geotechnical Results
2	Open Cut - No isolation	$ 1,287,195	1,838,850	$ 2,758,275	3rd CONTINGENCY	Contingent on DFO authorization
3	Pipe Live Lowering	$ 1,369,305	1,956,150	$ 2,934,225	*NOT RECOMMENDED*	Unknown asset condition & high risk activity
4	Station Relocation & Bridge Crossing	$ 1,550,430	2,214,900	$ 3,322,350	2nd CONTINGENCY	Contingency on DPW
5	Rip Rap Revetment - Cabled Concrete	$ 2,065,630	2,950,900	$ 4,426,350	*NOT RECOMMENDED*	Contingent on DFO authorization
6	Rip Rap Revetment - D50:300mm	$ 1,366,085	1,951,550	$ 2,927,325	*NOT RECOMMENDED*	Contingent on DFO authorization