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December 19, 2008

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. ("Terasen Gas")
Application for a Certificate of Public Convenience and Necessity ("CPCN") for the Fraser River South Arm Crossing Upgrade (the "Application")

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

On November 6, 2008, Terasen Gas filed the Application as referenced above.

Terasen Gas respectfully submits the attached response to BCUC IR No. 1 in advance of the deadline for IR responses as established in Commission Order No. G-173-08.

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

Yours very truly,

TERASEN GAS INC.

Original signed:

Tom A. Loski

Attachment

cc (e-mail only): Registered Participants

1.0 Reference: Exhibit B-1, pp. 8, 9, 14

1.1 Further to the reference to CSA Z662, does this standard require the use of any specific seismic design criteria in terms of return period or otherwise? Do any other applicable standards require the use of specific seismic withstand criteria?

Response:

CSA Z662 does not require the use of any specific seismic design criteria such as return period or otherwise. However, CSA Z662 Clause 4.2.4 does require designers to determine whether supplemental design criteria are necessary. TGI selected the seismic design criterion of a 2,475 year return period event for this critical crossing, consistent with local utility practice and US guidelines for major lifeline infrastructure. This criterion is also consistent with the NBCC design criterion for life safety of inhabited structures.

Terasen Gas is not aware of other applicable formal standards which require the use of specific seismic withstand criteria.

1.2 The Application states that the ability to withstand a seismic event with a return period of 2000 years (2.5% probability of exceedence over 50 years) is commonly used by other utilities. Please provide a summary of the criteria used by other gas transmission and distribution utilities along the West Coast, including Spectra Energy, Pacific Gas and Electric and Southern California Gas. Please discuss any significant differences in the criteria used.

Response:

In discussions with other utilities and from access to public information, TGI is aware of the following examples of seismic criteria used along the West Coast:

- BC Transmission Corp capital plan filings with BCUC cite a seismic risk criterion of 2% probability of exceedance in 50 years.

- Metro Vancouver has advised Terasen that it is using the 1/2,475 earthquake as per NBCC 2005 (since its publication) and is in the process of updating their standard to the new code.

- Spectra Energy Transmission advises that if it were to design any new major assets in the region, it would use asset-specific and site-specific risk analyses.

- The National Energy Board's 2000 decision on the proposed Georgia Strait Crossing (GSX) required the proponents to revise their design criterion from a 10% probability of exceedance in 50 years to a 2% probability of exceedance in 50 years.

- It is TGI's understanding that PG&E and Southern California Gas refer to the same seismic design guidelines as does TGI's seismic design standard. These guidelines, which are referenced in California and Oregon utility regulations refer to the same seismic design guidelines as does TGI's seismic design standard. Those guidelines do not mandate specific criteria, but do make reference to the use of International Building Code (IBC) seismic hazard maps for a 2% probability of exceedance in 50 years.

Utilities generally select seismic design criteria based on site-specific risk analyses, including life-safety issues, operational alternatives, and the extent and duration of impacts to customers. TGI's interpretation is that that for most critical lifeline systems, a return period of 2,475 years for design seismic ground motions is quite typical.

1.3 Further to the statement on page 9 that a strong earthquake will likely leave the existing pipelines unsupported, and Appendix 3, please explain why the new HDD crossings will not be at a similar risk of failure. Please include a diagram showing the depths of the existing lines and the proposed depths of the HDD crossings in the response.

Response:

The new HDD crossings will avoid all areas subject to loss of soil support in an earthquake. As shown on the profile drawings included in Attachment 1.3, the new HDD crossings will pass under the river and its banks through firm to stiff soil material, at depths where liquefaction will not occur in a design seismic event. On land, the new crossings will transition back to standard depth approximately 300 m inland from the river banks, beyond the predicted zone of lateral spread. Appendix 5, Golder's 2008 Report – Figures 6-9 and 6-10, show the extent of potentially liquefiable soils.

1.4 Page 14 refers to "the soil depth needed to address the seismic design requirements". If these depth requirements are not fully explained by the response to the previous question, please explain them.

Response:

The depth requirements are fully explained in response to BCUC IR 1.1.3 above.

1.5 Please explain why soil liquefaction is likely to cause a pipeline to rupture, and the pipeline stress and failure mechanism involved. If this risk is limited to underwater pipelines and is not a concern for on-land pipelines where there is risk of soil liquefaction, please explain.

Response:

Liquefaction poses a hazard to pipelines by reducing soil shear strength which can lead to ground displacements

The primary liquefaction-related hazard to TGI's Coastal Transmission System is lateral spread, which induces horizontal displacement of surficial (often competent) soil layers ranging up to several meters thick. These soil layers may slide down gentle slopes or, more commonly, toward a free face (i.e. an incised river channel or shoreline bluff) and impose large deformations in pipelines located in the surficial soil layers. Lateral spread displacements may extend back 100m or more from river channels and cause tensional pipeline failures at the up-slope (head) of the soil spread, pipeline shear failures along the margins of the soil spread, and pipeline compression failures such as buckling at the toe of the soil spread.

Where soil is not susceptible to lateral spread displacement, liquefaction may still pose a risk related to buoyancy effects, but to a lesser degree. In areas where these soil conditions exist, TGI mitigates this risk by constructing pipelines with concrete coating or external weights.

Although on-land pipeline failures are possible in a seismic event, TGI's consultants have identified liquefaction and lateral spread at river crossings as the predominant risk to the TGI Coastal Transmission System.

1.6 Please discuss the potential benefits of drilling deeper than the proposed depths for the HDD crossings so as to achieve a higher level of seismic withstand capability, and the cost of doing so.

Response:

TGI and its expert consultant believe there is no benefit from drilling the HDD crossings deeper than proposed. There is high confidence, based upon site-specific investigations

and regional geology that the non-liquefiable soil layer extends well below the proposed HDD elevation. Drilling deeper into the non-liquefiable soil layer would not increase the seismic withstand capability.

The cost to lower the depth of the HDD crossing would depend on the increment of HDD borehole work and pipeline required.

1.7 Page 11 refers to the need to raise the dyke crest on the north bank by an additional 0.65 m above its present elevation to meet provincial flood protection standards. What plans are in place to do this and what is the timing.

Response:

The City of Richmond has produced designs for the dike modifications and has commenced interim dike improvements to mitigate the winter storm surge risk to the dike. TGI expects the completion of the proposed dike work over the TGI ROW to occur immediately following the pipeline replacements.

1.8 On page 11 the following is stated: "failure of both crossings would leave 117,000 TGI customers isolated for a long period of time with no alternative gas supply." Please outline your estimates on the impacts to your customers' facilities, time to recover, and related impacts on gas requirements in the event of a seismic occurrence capable of creating severe damage to both crossings.

Response:

The Application states on page 11 that the figure of 117,000 TGI customers isolated is based on typical, above-freezing winter weather, representing approximately 50% of system design load. In fact, the number of customer accounts affected would increase to 200,000 under design conditions. Note that these estimates are based on the numbers of customers at present, and would increase over time as new customers are added to the system.

Table 6.2 of the Application documents that under normal conditions it would take 12 months to acquire the necessary resources and install two new HDD crossings. However, as stated on Page 12 of the Application, TGI anticipates that if both crossings failed, restoration could be expected to take a minimum of six months, and only if extraordinary levels of assistance are available. The re-light would take an additional month or more, depending on the number of technicians that could be mobilized.

It is difficult to provide estimates on the direct and related impacts to customers' facilities in the event of a seismic occurrence capable of creating severe damage to both existing crossings. However, some insights are available from studies and reports such as:

- Munich Re-insurance Company of Canada (1992): *A Study of the Economic Impact of a Severe Earthquake in the Lower Mainland of British Columbia*, which suggested at page 58 that "natural gas systems are potentially the most problematic of lifelines following an earthquake," and at page 59 that "…..a 50% benchmark curtailment……to gas-using industries in the Lower Mainland could lead to an approximate economic loss of $0.5 - $3.5 billion……if the cut off remained in effect for a full year."
- The Royal Commission (1999): *The ESSO Longford gas plant accident: Report of the Longford Royal Commission, Parliament of Victoria, Melbourne (1999),* and http://www.health.vic.gov.au/environment/downloads/risk_communication_app1.pdf. The September 1998 ESSO Longford gas plant explosion in the Australian state of Victoria caused a complete interruption of gas supply to an estimated 1.4 million households and 89,000 businesses, directly affecting the daily lives of some 4 million Victorians for 19 days. The estimated cost of that accident to the Victorian economy was put at AUD$1.3 billion.

To avoid the severe consequence of gas interruption to its customers resulting from a strong seismic occurrence, or other physical damage such as river scour or the ongoing effect of soil loadings from the dikes, TGI is committed to the immediate upgrading of both NPS 20 and NPS 24 crossings. TGI believes a long-term safe and reliable gas supply through the back-bone of the Lower Mainland distribution system is vital to the social and economic well-being of hundreds of thousands of customers in the region.

2.0 Reference: Exhibit B-1, Appendix 5, p. iv

"The results from the pipeline analysis for the 2,475 year ground displacements indicate that the HDD replacement of the NPS 20 or NPS 24 pipelines will easily survive the ground displacements associated with ground motions having a mean return period of 2,475 years (4th generation seismic hazard mapping)."

2.1 What is the return period of ground displacements that could lead to a loss of pressure event on the HDD replacement of the NPS 20?

Response:

TGI and its expert consultants believe that locating the HDD replacement of the NPS 20 pipeline in non-liquefiable soil layers as proposed will result in a seismic withstand capability exceeding ground motions having a mean return period of 2,475 years, and potentially as great as 5,000 to 10,000 years. By the nature of the proposed HDD methodology, the crossing will withstand ground motions having a significantly higher mean return period than 2,475 years. In fact, there is no other suitable, or less costly, construction methodology that exactly achieves a mean return period of 2,475 years or anything between 2,475 and 5,000-10,000 years.

2.2 What is the return period of ground displacements that could lead to a loss of pressure event on the HDD replacement of the NPS 24?

Response:

Response to BCUC IR 1.2.1 above applies equally to the HDD replacement of the NPS 24 pipeline.

3.0 Reference: Exhibit B-1, pp. 15-19

3.1 For the on-land and underwater segments of the NPS 20 pipeline between Tilbury Gate and Nelson Gate that would not be replaced in Alternative 1, please describe the pipeline in terms of age, wall thickness, grade of steel and method of manufacture.

Response:

The pipe that will not be replaced by Alternative 1 on the NPS 20 pipeline are as follows.

Location	Length (m)	Grade (MPa)	Wall Thickness	Material Specification*	Installation date
Tilbury Gate to Entry Point	500	290	7.1	API 5L	1959
Exit Point to Nelson Gate	400	414	7.1	CSA Z245	1998
	100	386	12.7	API 5L	1998
	170	359	9.5	CSA Z245	2001

*TGI's records the material standards the pipe was specified under as part of it's normal records database. The specific methods of manufacture ie, ERW; SMAW, or DSAW has not been an integrity issue to date. Flash welded pipe and low frequency ERW pipe have not been accepted.

All of the above pipe is for the "on-land" pipe. There is no underwater portion to remain in service after the Alternative 1 upgrade.

3.2 Please provide a summary of the latest internal line inspection run on the NPS 20 pipeline segments, including a review of the condition of the line and its coating, any defects found and/or investigated and any repairs made to the pipeline. Please respond separately for the on-land and underwater sections.

Response:

The NPS 20 pipeline between Tilbury Gate and Fraser Gate was inspected in 2000 using both inertial geometry and metal loss internal inspection tools. The NPS 24 pipeline between Nichol Valve Station and Fraser Gate was inspected in 2004, also with both inertial geometry and metal loss internal inspection tools. The tools did not identify any significant anomalies in these pipelines either in the water crossing sections or the on-land sections upstream and downstream of the crossings. A limited number of excavations were carried out on both pipelines and no significant corrosion and no instances of Stress Corrosion Cracking were found. The coating condition was generally good on both pipelines.

3.3 What does TGI expect will be the likely time when the on-land portion of the NPS 20 pipeline will need to be replaced due to corrosion, coating breakdown, stress cracking, population encroachment or other reasons?

Response:

As indicated in the response to BCUC IR 1.3.2, the initial in-line inspections (ILI's) and subsequent digs indicate that both the NPS 20 and NPS 24 between Tilbury Gate and Nelson Gate are in good condition. Following these initial ILI's, TGI examined both lines for external corrosion, SCC and coating condition and no significant concerns were identified. Cathodic Protection records also indicate that both lines are protected. The area surrounding these lines is zoned agricultural or commercial and there is no foreseeable risk of Class 4 designation. Terasen will continue to monitor these lines through on-going ILI and other inspection processes and currently does not see the need to replace either of these lines in the foreseeable future other than the segments proposed to be replaced in Alternative 1.

3.4 Please repeat the previous three questions with respect to the on-land and underwater segments of the NPS 24 pipeline between Tilbury Gate and Nelson Gate.

Response:

Please refer to responses to BCUC IR 1.3.1 to 1.3.3 above.

4.0 Reference: Exhibit B-1, pp. 15, 18-19

4.1 In terms of pipeline flow capacity between Tilbury Gate and Nelson Gate, please provide and compare the capacities of the following pipelines as well as the year during which their design day flows are expected to reach their capacities:

- NPS 20
- NPS 24
- NPS 20 and NPS 24
- NPS 24 and NPS 24
- NPS 30
- NPS 24 and NPS 30
- NPS 36
- NPS 24 and NPS 36

Response:

The existing NPS 20 and NPS 24 pipelines provide approximately 520 MMscfd in design day throughput capacity. This capacity is sufficient to meet the forecasted design day flows within the 20-year long range planning period ending in the winter of 2028/2029.

To demonstrate the adequate sizing of the existing NPS 20 and NPS 24 for the long term, an estimate of forecast growth for 50 years is used to check against the pipeline capacities. Beyond the normal 20-year planning period, the forecast growth assumes a stabilized long range peak day demand growth rate, which is equivalent to the average growth rate from the initial 20 years for the Metro Vancouver area of approximately 0.5% per year.

Table 4.1 below summarizes the pipeline flow capacities between Tilbury Gate and Nelson Gate for the various pipeline size combinations and the expected year at which the design day flows reach the respective pipeline capacities. The existing NPS 20 & NPS 24, as well as for the single NPS 30, have sufficient pipeline capacities to meet the design day flows beyond a 50 year period based on the assumptions above.

Table 4.1

Pipeline Size Combination	*Equivalent Capacities to NPS 20 plus 24*	*Year at which design day flows exceed pipeline capacities*
NPS 20 only	38%	Immediately
NPS 24 only	62%	Immediately
NPS 20 & NPS 24	100%	Greater than 50th year
NPS 30 only	103%	Greater than 50th year
NPS 24 & NPS 24	121%	Greater than 50th year
NPS 24 & NPS 30	126%	Greater than 50th year
NPS 36 only	150%	Greater than 50th year
NPS 24 & NPS 36	214%	Greater than 50th year

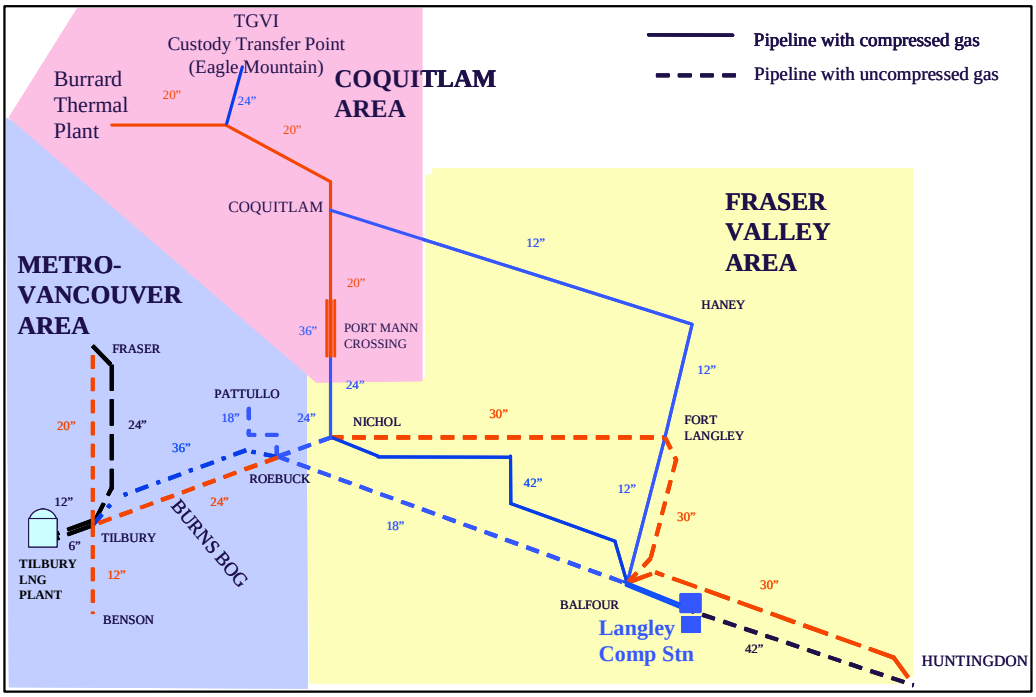
The Coastal Transmission System (CTS) is a network rather than a single bullet line; therefore, the system capacity constraints are not determined in isolation. As discussed in the TGI's 2008 Resource Plan [pp. 59], and as illustrated in Figure 4-1 below, the majority of the CTS in the Fraser Valley and Metro Vancouver areas is already looped and consequently has sufficient capacity to meet long-term demand requirements. The single feed pipeline from Nichol in Surrey to Coquitlam, TGVI and Burrard Thermal could potentially be capacity constrained in the long term. TGI has four alternatives available to solve this capacity constraint:

- Looping the Nichol to Coquitlam Pipeline,
- Adding more compression at the Langley Compressor Station,
- Building a new compressor station closer to the constraint location, and
- Expanding the existing Tilbury storage facility.

However, with the TGVI Mt. Hayes storage facility in operation by the winter of 2011/2012, it will reduce TGVI's transportation requirements during peak periods across the CTS and alleviate the capacity constraint on the CTS, potentially by as much as 150 MMscfd. This will eliminate any minor pipeline capacity deficiency throughout the CTS.

In summary, TGI does not expect any capacity constraint on the CTS for the long term, provided the existing pipeline sizing including the existing crossings of the Fraser River South Arm from Tilbury remains the same or equivalent. Therefore, the replacement of the existing NPS 20 and NPS 24 crossings by the same size pipelines is sufficient for the long term. Any other combination of pipeline sizing that offers greater system capacity than a NPS 20 & NPS 24 is not necessary, including NPS 24 & NPS 24, NPS 24 & NPS 30, NPS 36 only, or NPS 24 & NPS 36.

Figure 4-1 CTS Schematic



4.2 On page 15, TGI refers to a post earthquake consideration being the capacity of the remaining facilities within the 20-year long range planning period. What is the current capacity requirement for this crossing, and what is the maximum capacity requirement over the 20 year planning period?

Please indicate whether all of the assumptions regarding population growth, changes in customer capture rates, and changes in use per account that were used in developing the 20 year forecast were the same as those used to prepare the Reference Case forecast of TGI's 2008 Resource Plan. If the assumptions differ, then please provide an explanation for the difference.

Response:

The design day flow across the crossing is forecasted to be 350 MMscfd for the winter of 2008/2009, and growing to 390 MMscfd for the winter of 2028/2029. As indicated in the response to BCUC IR 1.4.1 (Table 4.1), the NPS 20 and NPS 24 crossings, respectively, provide 38% (199 MMscfd) and 62% (322 MMscfd) of the total 520 MMscfd in pipeline flow capacity. Consequently, both crossings are required to meet the current design day

flow as well as the expected design day flow for each year in the 20 year planning period.

All of the assumptions regarding population growth, changes in customer capture rates, and changes in use per account that were used in developing the 20 year forecast were the same as those used to prepare the Reference Case forecast of TGI's 2008 Resource Plan.

4.3 What is the expected life of the new underwater crossings?

Response:

The expected life of the new underwater crossings is greater than 50 years.

4.4 Noting that the NPS 20 crossing is 50 years old, what is the capacity required at the Tilbury Gate to Nelson Gate crossing in 50 years time?

Response:

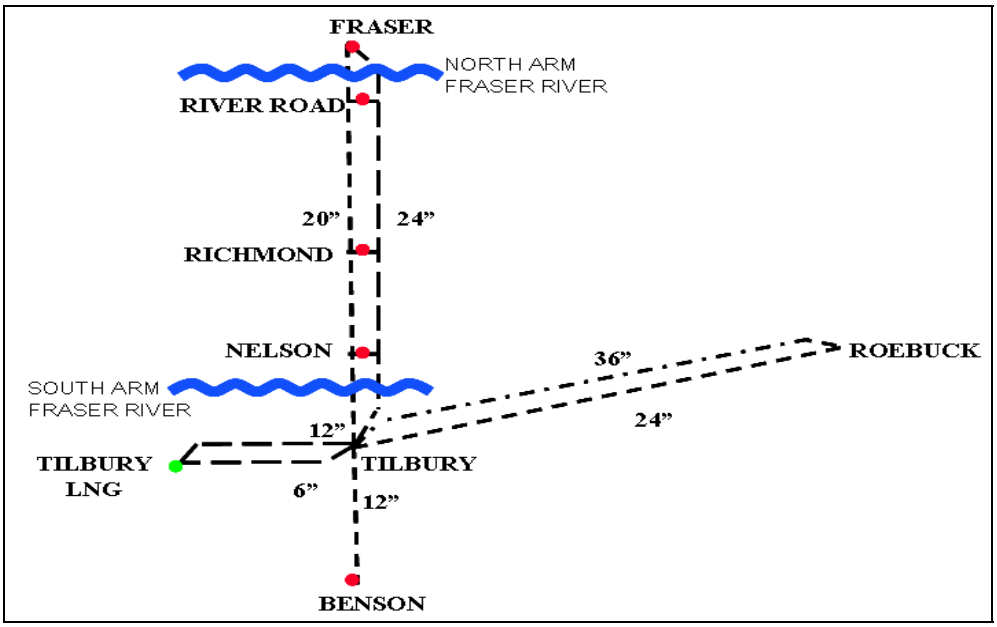
The design day flows at the Tilbury Gate to Nelson Gate crossing in 50 years time is estimated to be approximately 450 MMscfd.

4.5 Please provide a list of the pipelines and their sizes that currently are connected to each of Tilbury Gate and Nelson Gate.

Response:

Figure 4-5 shows the pipelines and their sizes that are currently connected between Tilbury Gate to Nelson Gate to Fraser Gate.

Figure 4-5



Pipelines that are interconnected at Tilbury Gate are:

- ROEBUCK TILBURY NPS 24
- ROEBUCK TILBURY NPS 36
- TILBURY LNG PLANT NPS 6
- TILBURY LNG PLANT NPS 12
- TILBURY BENSON NPS 12
- TILBURY FRASER GATE NPS 20
- TILBURY FRASER GATE NPS 24

Pipelines that are interconnected at Nelson Gate and Fraser Gate are:

- TILBURY FRASER GATE NPS 20
- TILBURY FRASER GATE NPS 24

4.6 In Alternative 4, please explain why TGI chose to use NPS 30 for the new crossing.

Response:

TGI considers the use of a single NPS 30 crossing in Alternative 4 as it would provide approximately the equivalent throughput capacity as the combination of NPS 20 & NPS 24 crossings. However, TGI does not consider this alterative as the preferred option for the following reasons:

- High cost compared to other alternatives, but with increased cost uncertainty.
- Significant increase in scope, number and duration of landowner, tenant, and environmental/land restoration impacts from open trench construction activities, which would extend to either side of the crossing by 2.8 km.
- Lack of a parallel pipeline for a critical underwater crossing to provide long-term reliability and operational flexibility.

4.7 Please explain why TGI did not consider as an alternative the replacement of the NPS 20 and NPS 24 with two pipelines, each having a nominal pipe size of 24 inches (NPS 24).

Response:

As discussed in the response to Q4.1 above, replacement of the NPS 20 and NPS 24 with greater pipeline sizing is not necessary.

In addition, the in-line inspection (ILI) program for the TP 20" requires running intelligent tools from Tilbury Gate Station to Fraser Gate Station. This requires a constant pipe size from launch to trap. Any increase of pipe diameter for the river crossing section of this NPS 20 line would require additional launchers and traps, with increased capital costs and land requirements. There would also be additional ILI runs at increased O&M, as well as disruption to businesses adjacent to the ROW.

For these reasons, TGI would not consider a replacement of the existing NPS 20 and NPS 24 crossings with two NPS 24 pipelines.

4.8 Please provide a cost estimate for Alternative 4 assuming the costs and benefits of using the larger line size of NPS 36 (about 914 mm), compared to Alternative 4 as proposed.

Response:

As discussed in the response in BCUC IR 1.4.1, the additional pipeline capacity offered by the larger line size of NPS 36 is not deemed necessary and does not offer any other additional benefit.

For the purposes of responding to this IR, TGI prepared an Alternative 5 – NPS 36 cost estimate using the same general estimate basis as the estimate for Alternative 4 - NPS 30. However, the cost estimate is not to the same accuracy as the ones prepared for Alternatives 1 to 4, due to insufficient time to gather the required supporting data. It therefore has a range accuracy of -25% + 30%. The cost estimate follows:

	Alternative 5: NPS 36 HDD and NPS 20 Replacement	Estimate ($2008 millions)
1	Project Management, Engineering, Consultation, Inspection	$ 4.4
2	Land Utilization, Temporary Workspace	$ 2.6
3	Pipe & Coating Materials	$ 9.0
4	River Crossing HDD Installation & Pipeline Construction	$ 15.3
5	Tie In Construction	$ 5.0
6	North Bank Dike Improvements Allowance	$ 1.0
7	Operations & Commissioning	$ 0.6
8	Sub- Total	$ 37.9
9	Retirement Costs (existing NPS 20 and NPS 24)	$ 0.2
10	AFUDC	$ 1.4
	Total Project	**$ 39.5**

4.9 For the proposed HDD crossing, what wall thickness, grade of steel and pipeline coating does TGI propose for each of NPS 20, NPS 24, NPS 30 and NPS 36?

Response:

TGI proposes the following pipe specifications for the Fraser River South Arm Crossing Upgrade Project for the proposed HDD Alternatives:

Linepipe Size	NPS 20	NPS 24	NPS 30	NPS 36
Grade (MPa)	448	483	483	483
Wall Thickness (mm)	12.7	14.2	17.7	21.2
Coating	Dual powdered fusion bond epoxy. Primary layer 350µm nominal thickness, Secondary layer 700µm nominal thickness c/w overcoat for UV resistance.			

4.10 Please explain why the proposed pipeline coating(s) are fully appropriate for the service.

Response:

The proposed pipeline coating is fully appropriate as the dual powder fusion bond epoxy system is a proven material for HDD crossings.

This system consists of two layers of coating designed to achieve abrasion resistance and enable cathodic protection. The first layer is a primary anti-corrosion layer of Fusion Bond Epoxy ("FBE") which is selected to have flexibility, impact resistance, good adhesion to steel, and defined moisture permeation for compatibility with cathodic protection. The second layer is a thicker anti-abrasion coating utilizing a different FBE selected to meet both the expected geotechnical conditions and HDD design profiles. The dual FBE system has undergone industry standard tests for impact and abrasion resistance.

TGI and many other pipeline companies have used successfully this coating system on many other HDD projects.

The coatings will be shop applied to both CAN/CSA-Z245.20-M92: External Fusion Bond Epoxy Coating and NACE RP0394: Application, Performance, and Quality Control of Plant Applied, Fusion-Bonded Epoxy External Pipe Coating.

A quality control program including shop and field inspection and testing will ensure specified coating properties are achieved.

4.11 With reference to Alternative 1. At what time in the future are the new NPS 20 and NPS 24 Crossings likely to no longer meet demand in terms of capacity?

Response:

As discussed in the response to BCUC IR 1.4.1, the combined pipeline capacities of the new NPS 20 and NPS 24 crossings would be sufficient to meet the forecast peak day flows beyond a 50 year period.

5.0 Reference: Exhibit B-1, pp. 16, 25-27, 37, Appendix 13

5.1 Further to Appendix 13, please provide detailed cost estimates for each Alternative and for Alternative 4 assuming a NPS 36 HDD Replacement. Please outline the work involved and explain the basis for the estimate for significant items.

Response:

The detailed cost estimates for Alternatives 1 to 4 are listed in Appendix 13. Please see the response to BCUC IR 1.4.8 for a cost estimate for a NPS 36 HDD Replacement. Note that the accuracy of the estimate for the selected NPS 20 and NPS 24 option will be improved upon the development of a control budget.

The significant items of work involved in Alternatives 1 to 4 are listed in Appendix 13, and are as described in Sections 5 and 6 of the Application. The estimates in Appendix 13 were based on:

- historical construction costs of similar work of similar scope;
- non-binding vendor estimates for material and equipment supply;
- published land values; and
- market prices for a defined level of professional and labour services for project execution.

5.2 Please complete the following table for Alternative 1, assuming the project is to be completed in 2009.

ESTIMATE DATA				PROJECT TIMELINE	
DOLLARS IN NOMINAL	**WACC** %	**USEFUL LIFE** *(years)*	**AACE ESTIMATE CLASS**	**PROJECT START DATE** *(YYYY/MM/DD)*	**IN-SERVICE DATE** *(YYYY/MM/DD)*

ESTIMATED COST AT COMPLETION				
	ESTIMATED COST AT COMPLETION ($ 1,000,000)	**ESTIMATE ACCURACY**	**ENGINEERING COMPLETED %**	
BEST CASE *(P10)*			**AFUDC $ SPENT TO DATE**	
WORST CASE *(P90)*			**INTERNAL REVIEW** *(yes/no)*	
EXPECTED COST *(P50 or other)*			**EXTERNAL REVIEW** *(yes/no)*	

ESTIMATE COST DATA	
WORK BREAKDOWN STRUCTURE ELEMENT *(at WBS Level 3 or higher)*	**ESTIMATED COST (Dollars x 1,000)**
Interest During Construction (Cost of Money)	
CORPORATE & ADMINISTRATIVE COSTS	
UNDISTRIBUTED COSTS	
PERFORMANCE MEASUREMENT BASELINE *(*PMB)	
PROJECT RESERVE	
PROJECT COST *(Performance Measurement Baseline including Project Reserve)*	
FIRST NATIONS CONSULTATION AND ACCOMODATION COSTS	
LEGAL COSTS	
OTHER REGULATORY COSTS *(provide a separate listing in a similar table)*	
BC EAO REGULATORY COSTS	
BCUC REGULATORY COSTS	
OTHER NON-PROJECT COSTS *(provide a separate listing in a similar table)*	
CONTINGENCY (*without escalation or inflation)*	
ESCALATION *(including Inflation)*	
TOTAL PROJECT COST (TPC)	

Response:

As indicated in the Application, TGI proposes to file an updated Project cost estimate with the Commission prior to the start of construction, which will incorporate new information, including the contractor bid that TGI has selected for the directional drill portion of the work. The table will therefore be completed upon creation of the control budget.

5.3 Please repeat the previous question for Alternative 1, to be completed in 2010.

Response:

Please refer to the response to BCUC IR 1.5.2, and the Schedule in Appendix 7 of the Application that proposes major construction activities will occur in 2009. However, TGI will prepare both a 2009 and 2010 cost estimate after receipt of the material tenders, finalization of landowner agreements and HDD – pipeline construction tender as part of the control estimates process (refer to Section 6.3 of the Application) to finalize which year is most cost effective. Therefore, at this time, there is no cost difference in the cost estimate between 2009 and 2010 in current dollars.

5.4 Please explain the basis for estimating that efficiencies of at least $6 million will be realized by doing both HDD crossings at once. What is the range of accuracy of this estimate?

Response:

The basis for estimating that both HDD crossings will achieve $6 million efficiencies was developed by preparing two separate cost estimates for each alternative from the same level of Project planning, and then eliminating the incremental overlap in the individual estimate elements that would occur if the two alternatives were performed via simultaneous or continuous construction activities as applicable.

TGI expects the range of accuracy of this estimate to be –15% +20% as the individual estimates were prepared to that range of accuracy.

5.5 Please provide details behind the $1.8 million estimate for land and temporary work space.

Response:

The estimate for land and temporary workspace was developed following meetings and discussions with land owners, preliminary land assessments, and an assumed Project schedule and work plan as described in the Application. The details behind the estimate includes land rental for a pipe storage yard, temporary workspace, appraisals, legal services, land surveys, property consultant, building inspections, agricultural crop loss or recovery, and potential business loss or disruption accommodation costs.

Due to the commercial sensitivity of the information requested, the response to this question has been filed under separate cover in accordance with the BCUC Practice Directive pursuant to Section 13 of the *Administrative Tribunals Act* related to Confidential Filings. The Terasen Utilities have requested that the information be made accessible only to the Commission.

5.6 Please confirm that the accuracy of the cost estimate for each of Alternatives 1 to 4 is -15 +20 percent, or provide the range for each alternative.

Response:

Cost estimates for Alternatives 1 to 4 inclusive were prepared from the same cost estimate basis. TGI believes it produced a total accuracy range for each Alternative of -15 +20 percent.

5.7 Please state whether a cost risk analysis for each of the Alternatives has been performed and, if so, whether the -15+20 percent range of project costs corresponds to P10 and P90 estimates respectively.

Response:

A cost risk analysis that can be used to determine P10 to P90 confidence levels will be completed at the same time as the development of the control budget. As indicated in the Application, TGI proposes to file an updated Project cost estimate with the Commission prior to the start of construction. The control budget is to incorporate new information, including the contractor bid that TGI has selected for the directional drill portion of the work. TGI will include the results of the cost risk analysis and a comparison to the current -15 +20 percent range with that submission.

5.8 Please provide a cost risk analysis that is the basis for the statement on page 25 of the Application that "the expected accuracy of the cost estimate is -15 to +20%".

Response:

Please refer to the response to BCUC IR 1.5.7.

5.9 Please present the expected range of costs for each item identified in Table 6.1.

Response:

	Alternative 1: NPS 20 and NPS 24 HDD Replacement	**($2008 Millions)**		
		LOW	**Estimate**	**HIGH**
1	Project Management, Engineering, Consultation, Inspection	4.3	4.9	5.3
2	Land Utilization, Temporary Workspace	1.1	1.8	3.2
3	Pipe & Coating Materials	3.4	3.6	4.5
4	River Crossing HDD Installation & Pipeline Construction	10.2	11.6	13.7
5	Tie In Construction	2.2	2.5	2.8
6	North Bank Dike Improvements Allowance	0.25	1	1.25
7	Operations & Commissioning	0.5	0.6	0.7
8	**Sub- Total**	**22.0**	**26**	**31.4**
9	Retirement Costs (existing NPS 20 and NPS 24)	0.3	0.4	0.5
10	AFUDC	0.8	0.9	1.0
	TOTAL PROJECT	**23.1**	**27.3**	**32.8**
	Percentage versus Estimate	*- 15%*		*+ 20%*

5.10 TGI states that it is committed to minimizing the rate impact associated with the Project. Please explain how having the HDD contract conditional on Commission review and approval furthers this objective.

Response:

TGI is currently seeking approval from the Commission for a CPCN for the Project prior to finalizing the HDD contract and other contractual arrangements. Having prior Commission approval of the CPCN will give landowners, suppliers and contractors greater certainty the Project will proceed and will put TGI in the best position to tender and obtain competitively priced contracts to complete the Project. This in turn will help to mitigate the cost and subsequent rate impact of the Project.

TGI offered to bring forward the executed conditional contract to the Commission simply as a means of ensuring that the Commission is comfortable with the balance the agreement strikes between cost and the assumption of risk. TGI always strives to minimize rate impacts by achieving an appropriate balance between risk and cost, and is quite confident in its ability to strike the appropriate balance without returning to the Commission should the Commission wish to avoid additional process on this non-discretionary project. The response to BCUC IR 1.6.2 provides information about the type of contractual arrangement TGI will seek.

5.11 Please discuss when TGI expects to file a revised control budget. If the date is after the Commission makes a determination on the CPCN Application, please explain how the Commission will have adequate cost information before it is in order to make a determination on the Application.

Response:

TGI expects to have sufficient information to file a control budget in the spring of 2009, after receipt of the linepipe bids, land owner agreements and HDD/Pipeline contract bids.

As indicated in the Application at p.12, TGI considers this Project to be non-discretionary: *"Given the potential for the two crossings to fail, in particular the probability of failure in the event of a seismic event, and the consequences of such a failure discussed above, TGI has concluded that the risk associated with these crossings is unacceptable and remedial action is required."* TGI believes the cost estimates provided in the Application are within an acceptable accuracy range to rank the Alternatives in order to determine the optimum Alternative.

6.0 Reference: Exhibit B-1, pp. 27, 28

6.1 Using a 5x5 risk matrix of likelihood and impact on project cost, please rank the Risks shown in Table 6.3.

Response:

Using a 5x5 risk matrix, the risks outlined in Exhibit B.1, Table 6.3 has been ranked below with 1 being the highest risk, and 7 being the lowest.

Ranking Legend

1 HDD/Pipeline Contractor Capability
2 Construction Schedule
3 HDD/Pipeline Contract Cost
4 Material Cost/Delivery
5 Engineering/Construction Resources
6 Stakeholder
7 Project Management

RISK MATRIX

Likelihood	Low	Moderate	High
High			
		2	
Moderate		3,4	1
	6	5	
Low		7	

Cost Impact

6.2 Table 6.3 states that unforeseen or variable subsurface risks will be shared between the Contractor and TGI. Please discuss how this sharing will be arranged, the likely range of sharing and the resulting range of cost exposure to TGI and its ratepayers.

Response:

The unforeseen or variable subsurface risk sharing mechanism will be arranged by using construction specifications that define the HDD operational risks outside versus those within the contractor's control and the mitigation plan during the execution of the work.

The cost risks to be shared by the HDD contractor and TGI will be those associated with subsurface conditions which are not identified in or can be reasonably inferred from the geotechnical reports. For example, this would include encountering seams of gravels or boulders along the drill path which were not identified in the subsurface investigations, causing a loss of circulation of drilling fluid despite having followed proper pressure management, fluid management and hole cleaning best practices.

The contract documents will require that the HDD contractor assumes all of the risk for its own equipment reliability, personnel competency and any problems caused by the contractor's failure to remain within the tolerances of the HDD design and specifications.

The contract documents will require that TGI and the HDD contractor jointly manage construction activities and operational delays that result in an increased construction schedule beyond the base contract schedule, due to unforeseen subsurface conditions.

A lump sum arrangement will be developed for the base schedule, meaning that there will be a financial incentive for the contractor to effectively complete its work ahead of the time specified in the contract. Beyond the base schedule, the cost risks will be shared by TGI and the contractor in the form of tendered operating rates on a shift or day basis, consumables and third party expenditures multiplied by the jointly agreed time or quantities.

TGI expects that any delays due to unforeseen or variable subsurface conditions are likely to be non-routine and with low frequency. To minimize the risk, TGI has conducted extensive geotechnical investigations and is confident that the costs above the base HDD contract attributable to the unforeseen ground conditions sharing mechanism will not be a significant risk to Project costs.

The likely range of sharing and the resulting range of cost exposure to TGI and its ratepayers will be addressed in the cost risk analysis as part of the development of the control budget.

6.3 Further to Table 6.3, please explain whether TGI anticipates that the HDD/Pipeline contractor's bid price will include a premium to cover their apportioned share of the unforeseen or variable subsurface risks. If so, then please explain why a contract structured in such a manner is preferable to one wherein TGI bears all of the subsurface risks. If not, then please explain why a contractor would agree to bear a portion of the unforeseen or variable subsurface risks.

Response:

The apportionment of risk between the contractor and TGI related to unforeseen or variable subsurface risk will be evaluated as part of the tender process prior to finalizing the HDD contract. TGI does recognize that the contractor's lump sum components of the bid would contain a significant premium for unforeseen or variable subsurface risks if the contractor is required to solely bear these risks. Furthermore, a contractor may elect not to submit a proposal at all it if is required to assume all of the risks which could reduce TGI's ability to obtain competitively priced bids. On the other hand, TGI believes that a fair apportionment of risks provides appropriate incentive to the contractor to prudently manage its resources to cost effectively mitigate the impact of any unforeseen subsurface risk to the final Project costs.

TGI believes that the most effective HDD contracting strategy is one that incorporates a pricing strategy that includes:

- Lump sum components for defined items of work that are in the contractor's control such as mobilization, site security, worksite preparation, drilling, and pipeline testing.
- Unit price components where the specification of the work is fixed, the contractor is in control of the work, but the quantity will be variable such as casing installation, drilling cuttings disposal, supply of drilling fluids, and supply of granular materials.
- Unit price components and set mark ups for jointly agreed upon scope of work changes to the base contract for such activities such as to manage any subsurface changes, shut downs for adverse weather conditions, and land owner accommodations.

TGI believes that this HDD contract pricing structure would provide for the most cost effective approach for balancing construction risk sharing and project cost. .

6.4 Please provide a summary of the subsurface testing that TGI has carried out along the HDD route and to the expected drilling depth, and explain why TGI is confident that HDD will be successful at this location.

Response:

Profiles showing previous and proposed borehole/CPT locations (Figure 1, an update to Figure 8.1 of Appendix 5), and a summary of subsurface data (update of Table 2.1, Appendix 3) are included as Attachment 6.4. Results of previous subsurface testing and existing regional geologic information have not revealed materials which are incompatible with successful HDD construction. Further testing underway on the land portions of the crossing will be used to confirm HDD entry and exit soil conditions, and to make minor adjustments to the drill path if necessary. TGI and its consultants are therefore confident that the HDD construction will be successful.

7.0 Reference: Exhibit B-1, pp. 35-36

7.1 Please provide the number of full-time utility personnel that TGI expects will be on the Project team. Also, please indicate whether utility personnel on the team represent incremental costs to the utility (such as those that may be incurred from backfilling of the team members' original job) that have not been reflected in the Project cost estimate.

Response:

TGI expects a total of 2 full time Utility personnel during the CPCN Application and Detailed Design Phases and may have one additional full time Utility person during the Construction Phase (3 in total) and a cost allowance has been included in the Cost Estimate. Furthermore, the Cost Estimate includes Utility personnel costs for those who are not full time on the Project and have not been budgeted elsewhere such as Engineering personnel. The incremental expenses, such as periodic backfilling of the team member's original job for those that have been budgeted elsewhere, have also been included.

8.0 Reference: Exhibit B-1, Appendix 3, pp. 9-11; Appendix 5, p. 25; Appendix 13

8.1 The cost estimate in Appendix 13 includes a $1.0 million allowance for North Bank Dike Improvements. Please explain what is contemplated.

Response:

The estimated allowance includes only the actual incremental costs for interim dike improvement construction and pipeline protection to ensure the dike complies with flood protection requirements. An interim dike improvement over the pipelines is to be designed and constructed until the pipelines are replaced. Dike settlement will continue to be monitored following interim dike construction. If the threshold settlement is reached, as determined by the preliminary monitoring, then supplementary ILI tools will be run to refine the measurement of the pipeline movements and subsequent operating stress calculations. Pipelines may have to be exposed within the dike ROW to relieve operating stresses.

8.2 The 2007 Golder Associates report states the combination of measures to satisfy TGI's seismic performance and risk management criteria include:

> "implementation of limited replacement of the NPS 24 T.P. pipeline at the east-west aligned offset at the southern bank of the river, including replacement of the existing 7.1 mm wall thickness, grade X52 pipe with 13.7 mm X60 pipe at the on-shore segment located north of the river dyke, and replacement of the existing 3D elbows with 12D induction bends;"

The 2008 Golder Associates report stated that:

> "If Terasen elects to rehabilitate the NPS 20 T.P. pipeline through HDD replacement, consideration could be given to implementing the previously-recommended onshore improvements to the NPS 24 T.P. pipeline. However, we recommend that a cost benefit analysis be considered to determine whether the implementation of such improvements would still be warranted given that it is unlikely that such improvements alone would be sufficient to meet Terasen's seismic performance standard for the ground motions corresponding to 1:2,000 year or 1:2,475 year return period based on 4th generation seismic hazard maps."

Please discuss the alternative of upgrading the NPS 24 line as recommended by Golder in their 2007 report, along with an HDD replacement of the NPS 20, in terms of reliability, capacity, seismic withstand capability, risk of river scour, dike loading problems, cost, and rate impact.

Response:

Upgrading the NPS 24 line at the south river bank along with an HDD replacement of the NPS 20, as recommended in Golder's 2007 report, would constitute a sub-set of Alternative 3 discussed in the application. TGI estimates the upgrade would cost $1.3 million more than Alternative 3, and would only marginally improve seismic withstand capability. As stated on page 4 of Appendix V within Appendix 5 of the Application, the upgraded NPS 24 line could be expected to withstand seismic events in the range of 800 – 1,200 year return period, as compared to 500 – 800 year events in its current state.

The upgraded NPS 24 pipeline would still be operating well out of compliance with TGI's seismic standard, and would thus remain a potentially significant post-earthquake emergency assessment and public safety response issue. Gas load capacity would be unchanged, dike loading problems would not be mitigated, and a small risk of river scour at the north bank would also remain. As shown the tables that follow, there would be an impact of 0.07 cents / GJ to rates in 2010. TGI does not believe the expenditure of $1.3 million would provide benefits of any significance relative to Alternative 3.

BCUC IR 1.8.2 ($000)

Alternative 3 Base Case Plus NPS 24 Limited Replacement

Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Incremental Mid-Year Rate Base	**$17,376**	**$17,178**	**$16,830**	**$16,482**	**$16,134**	**$15,786**	**$15,438**	**$15,090**	**$14,742**	**$14,394**
Incremental Cost of Service										
Depreciation Expense New Facilities	$348	$348	$348	$348	$348	$348	$348	$348	$348	$348
Avoided Depreciation Expense Retired Facilities	($19)	($19)	($19)	($19)	($19)	($19)	($19)	($19)	($19)	($19)
Income Tax Expense	($207)	($155)	($112)	($75)	($44)	($21)	($1)	$18	$35	$50
Earned Return on Rate Base	$1,300	$1,285	$1,259	$1,233	$1,207	$1,181	$1,155	$1,129	$1,103	$1,077
Total Cost of Service	**$1,422**	**$1,459**	**$1,475**	**$1,487**	**$1,492**	**$1,488**	**$1,483**	**$1,476**	**$1,466**	**$1,456**
Unit Cost of Service Impact										
Sales and Applicable Transportation Volumes (PJ/Yr)	153	156	158	160	163	165	167	169	172	174
Unit Cost of Service ($/GJ)	**$0.0093**	**$0.0094**	**$0.0093**	**$0.0093**	**$0.0092**	**$0.0090**	**$0.0089**	**$0.0087**	**$0.0085**	**$0.0084**
Unit Cost of Service Alt 3 Base Case ($/GJ)	$0.0086	$0.0087	$0.0086	$0.0086	$0.0085	$0.0084	$0.0082	$0.0081	$0.0079	$0.0077
Unit Cost of Service Difference ($/GJ)	**$0.0007**	**$0.0007**	**$0.0007**	**$0.0007**	**$0.0007**	**$0.0007**	**$0.0007**	**$0.0006**	**$0.0006**	**$0.0006**

Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Incremental Mid-Year Rate Base	**$14,046**	**$13,698**	**$13,350**	**$13,002**	**$12,654**	**$12,306**	**$11,958**	**$11,610**	**$11,262**	**$10,914**
Incremental Cost of Service										
Depreciation Expense New Facilities	$348	$348	$348	$348	$348	$348	$348	$348	$348	$348
Avoided Depreciation Expense Retired Facilities	($19)	($19)	($19)	($19)	($19)	($19)	($19)	($19)	($19)	($19)
Income Tax Expense	$64	$76	$87	$97	$106	$114	$121	$127	$132	$137
Earned Return on Rate Base	$1,051	$1,025	$999	$973	$947	$920	$894	$868	$842	$816
Total Cost of Service	**$1,443**	**$1,430**	**$1,415**	**$1,399**	**$1,381**	**$1,363**	**$1,344**	**$1,324**	**$1,303**	**$1,282**
Unit Cost of Service Impact										
Sales and Applicable Transportation Volumes (PJ/Yr)	176	178	181	183	186	188	191	193	196	198
Unit Cost of Service ($/GJ)	**$0.0082**	**$0.0080**	**$0.0078**	**$0.0076**	**$0.0074**	**$0.0072**	**$0.0070**	**$0.0069**	**$0.0067**	**$0.0065**
Unit Cost of Service Alt 3 Base Case ($/GJ)	$0.0076	$0.0074	$0.0072	$0.0071	$0.0069	$0.0067	$0.0065	$0.0063	$0.0062	$0.0060
Unit Cost of Service Difference ($/GJ)	**$0.0006**	**$0.0006**	**$0.0006**	**$0.0006**	**$0.0006**	**$0.0005**	**$0.0005**	**$0.0005**	**$0.0005**	**$0.0005**

Based on TGI current approved 64.99% - 35.01% debt equity structure, 8.62% ROE and 8% CCA rate.
Unit cost of service impact based on forcasted sales volumes and non-bypass transportation service volumes.
All costs presented in $2008

BCUC IR 1.8.2 ($000)

Alternative 3 Base Case NPS 20 HDD Upgrade

Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Incremental Mid-Year Rate Base	**$16,089**	**$15,917**	**$15,595**	**$15,273**	**$14,951**	**$14,629**	**$14,307**	**$13,985**	**$13,663**	**$13,341**
Incremental Cost of Service										
Depreciation Expense New Facilities	$322	$322	$322	$322	$322	$322	$322	$322	$322	$322
Avoided Depreciation Expense Retired Facilities	($19)	($19)	($19)	($19)	($19)	($19)	($19)	($19)	($19)	($19)
Income Tax Expense	($191)	($143)	($104)	($69)	($41)	($20)	($0)	$17	$32	$47
Earned Return on Rate Base	$1,203	$1,191	$1,166	$1,142	$1,118	$1,094	$1,070	$1,046	$1,022	$998
Total Cost of Service	**$1,315**	**$1,351**	**$1,366**	**$1,376**	**$1,381**	**$1,378**	**$1,372**	**$1,366**	**$1,357**	**$1,347**
Unit Cost of Service Impact										
Sales and Applicable Transportation Volumes (PJ/Yr)	153	156	158	160	163	165	167	169	172	174
Unit Cost of Service ($/GJ)	**$0.0086**	**$0.0087**	**$0.0086**	**$0.0086**	**$0.0085**	**$0.0084**	**$0.0082**	**$0.0081**	**$0.0079**	**$0.0077**

Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Incremental Mid-Year Rate Base	**$13,019**	**$12,697**	**$12,375**	**$12,053**	**$11,731**	**$11,409**	**$11,087**	**$10,765**	**$10,443**	**$10,121**
Incremental Cost of Service										
Depreciation Expense New Facilities	$322	$322	$322	$322	$322	$322	$322	$322	$322	$322
Avoided Depreciation Expense Retired Facilities	($19)	($19)	($19)	($19)	($19)	($19)	($19)	($19)	($19)	($19)
Income Tax Expense	$59	$71	$81	$90	$98	$105	$112	$117	$122	$126
Earned Return on Rate Base	$974	$950	$926	$902	$877	$853	$829	$805	$781	$757
Total Cost of Service	**$1,336**	**$1,323**	**$1,309**	**$1,294**	**$1,278**	**$1,261**	**$1,244**	**$1,225**	**$1,206**	**$1,186**
Unit Cost of Service Impact										
Sales and Applicable Transportation Volumes (PJ/Yr)	176	178	181	183	186	188	191	193	196	198
Unit Cost of Service ($/GJ)	**$0.0076**	**$0.0074**	**$0.0072**	**$0.0071**	**$0.0069**	**$0.0067**	**$0.0065**	**$0.0063**	**$0.0062**	**$0.0060**

Based on TGI current approved 64.99% - 35.01% debt equity structure, 8.62% ROE and 8% CCA rate.
Unit cost of service impact based on forcasted sales volumes and non-bypass transportation service volumes.
All costs presented in $2008

8.3 Page 9 refers to "an update to the 2007 analysis utilizing recently published updates to seismic data and modeling from the Geological Survey of Canada." Please confirm that this seismic data and modeling are what Golder Associates refer to in their 2008 report as the 4th generation GSC seismic hazard mapping.

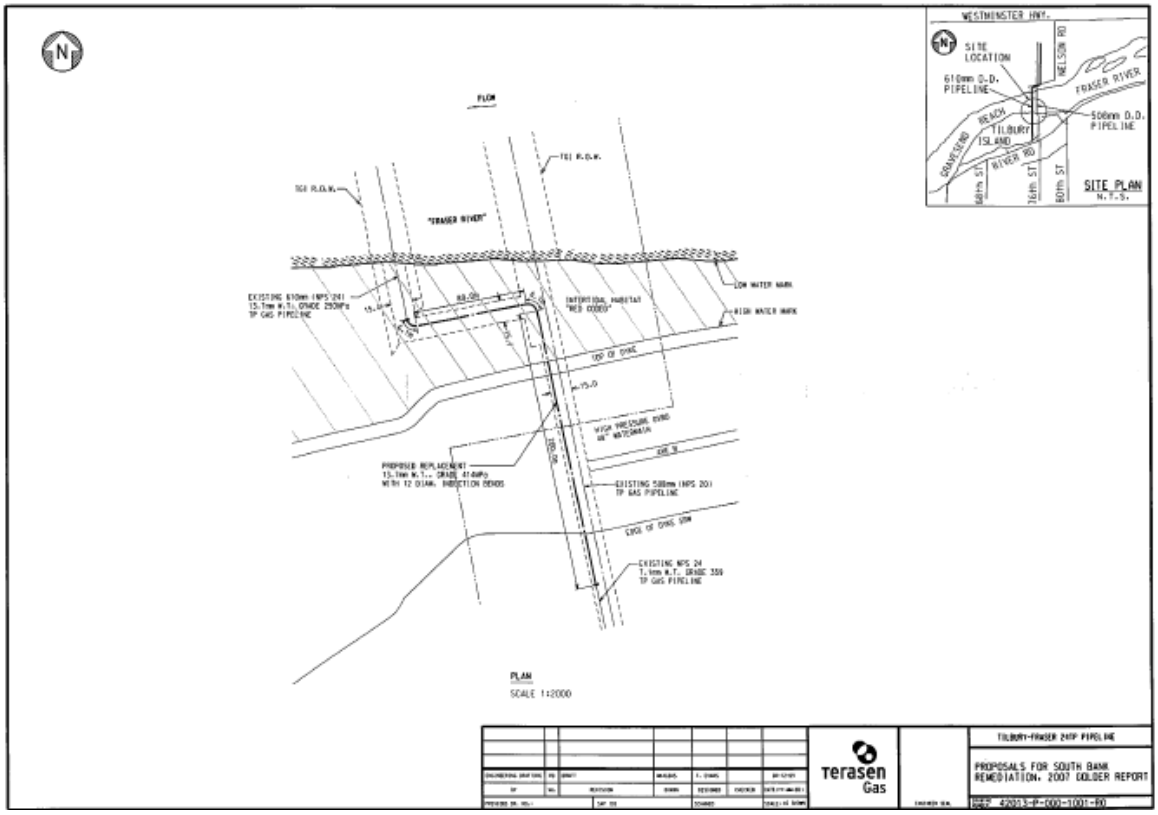
Response:

Yes, this refers to 4th generation GSC seismic hazard mapping.

8.4 Please provide diagrams illustrating the on-shore work at the north and south banks of the river that is recommended by Golder in their 2007 report, and a cost estimate for the work that would be involved.

Response:

The following diagram refers to the proposed remediation measures of the South Bank of the Fraser River from the 2007 Golder Report as referenced in Exhibit B-1. The cost for this proposed South Bank remediation is estimated at $1.3 million.



It should be noted that after further assessment the Company is of the view that the proposed 2007 Golder remediation measure is not appropriate because it will not withstand ground motions having a mean return period of 2,475 years, predicted from 4th generation seismic hazard mapping. As recommended by Golder in their 2008 report, HDD pipeline replacement is considered the only suitable rehabilitation technique for either or both pipelines.

The 2007 Golder Report does not provide for any remediation measures on the North Bank.

8.5 Please discuss whether the work proposed by Golder would deal with the potential dike loading issue with respect to the NPS 24 pipeline. If it would not, please describe what else would need to be done, and the cost of doing so.

Response:

The work described in the 2007 Golder report would not have accommodated the recognized dike loading issues with respect to the NPS 24 pipe and additional work would have been required. The dike improvement would require a design that:

- provides for a zero net increase to the surface load caused by earth filling or overlying structures which is bearing on the pipeline and surrounding compressible soils;
- provides for zero differential settlement of the pipeline within the compressible surrounding soils at the depth of the pipeline; and
- meets the requirements of the provincial Dike Maintenance Act.

To achieve these objectives, TGI contracted Golder who is experienced in dike and levee design, familiar with compressible peat soils and pipelines to investigate options. The non HDD pipeline replacement dike improvement recommendation that TGI believes best meets the above objectives includes:

- installing an incompressible foundation below the pipeline under the proposed dike structure using soil mixing ground improvement techniques;
- excavating the pipeline within the dike structure, dewatering, sheet piling as required, sectioning the pipeline to relieve stresses, and replacing a segment of pipe as required to re-lay pipe in a stress free state; and
- re-constructing the existing dike structure and the proposed dike improvements.

Scheduling of this work, which includes in-stream activities and low river levels, would need to meet the environmental window which is during the late summer.

Preliminary cost estimates were over $3 million.

9.0 Reference: Exhibit B-1, Appendix 5, p. i

9.1 Referring to the statement:

> "In 2004, the GSC developed the 4th generation seismic hazard maps as input to the seismic design provisions in the 2005 National Building Code of Canada (NBCC 2005) based on new seismogenic zones and seismic hazard models."

Please confirm whether or not the 4th generation seismic hazard maps were available in 2005, as the preceding statement would suggest.

Response:

The 4th generation GSC seismic hazard mapping was available in 2005. Please see the response to BCUC IR 1.9.2.

9.2 Referring to the above quote, please explain why the 4th generation seismic hazard maps were not used by Golder Associates in their 2007 study.

Response:

Golder Associates produced a summary report on Aug 9, 2007 for Terasen Gas (ref. Appendix 3) in order to document the findings from the work performed by Golder/DGHC up to early 2005 and to facilitate TGI obtaining a second opinion. The 4th generation seismic hazard maps were not used by Golder Associates in that report because the technical investigations and analyses being summarized took place before the 4th generation maps were officially published in 2005.

In December 2007 TGI commissioned Golder to expand their previous work in order to facilitate preliminary design of a crossing upgrade to support this CPCN Application. This request included use of the 4th generation seismic hazard maps, acquiring additional soils information and conducting further modeling of both pipelines. Golder's response to that request was their June 27, 2008 report (ref. Appendix 5).

10.0 Reference: Exhibit B-1, Appendix 3

10.1 Further to Figure 2-1 in Appendix 3, please provide larger scale forms of this Figure, in at least 11 x 17 size.

Response:

A large-scale diagram is provided in the response to BCUC IR 1.1.3, Attachment 1.3.

10.2 Please provide a large scale diagram similar to Figure 2-1 that shows the existing NPS 20 and NPS 24 pipelines, and also the proposed NPS 20 and NPS 24 pipelines, in both Plan and Profile.

Response:

A large-scale diagram is provided in the response to BCUC IR 1.1.3, Attachment 1.3.

11.0 Reference: Exhibit B-1, pp. 14-19

11.1 Further to the comparison of HDD Alternatives in the Application, please provide a schedule that compares Alternatives 1 through 4 plus Alternative 4 using a NPS 36 inch crossing on financial and non-financial bases.

The non-financial comparison of the five alternatives should be prepared using the criteria for evaluation set out in the Application, plus others that are appropriate such as pipeline capacity/long term sufficiency. As well as a weighted ranking table, please include definitions of the criteria used and a summary justifying the assigned readings. As an illustrative example, FortisBC Inc. included the following comparison in the application for the Okanagan Transmission Reinforcement Project as Exhibit B-1, Section 4, pages 41-48.

Table 4-3-2B below provides a cost and NPV analysis comparing the preferred route Alternative 1A with Alternative 1B which also uses the existing brownfield right-of-way. Both of these Alternatives have an in-service date of 2010 and both estimates are at the +20 / -10% preliminary design level. Estimate detail can be found in Appendix G.

Table 4-3-2B: Route Alternatives 1A & 1B 2010 in-service Cost & NPV Analysis

Alternative	1A	1B	2A	2B	3
	($000s)				
TOTAL CAPITAL COST	141,408	129,915	No costs are presented for these Alternatives due to time frame associated with acquiring a new right-of-way for the upland route.		
Net Present Value of Revenue Requirements	69,421	61,840			
One-Time Equivalent Rate Impact	2.28%	2.03%			

Alternative 1B is estimated to have the lowest cost regardless of whether the in-service date is 2010 or 2012. FortisBC submits, however, that it is not the most cost-effective alternative when consideration is given to other non-financial project attributes such those discussed in section 4.3.3 below.

4.3.3 Non-Financial Comparison

A non-financial comparison of the five alternatives was prepared using criteria for evaluation that are generally consistent with those put forth with previous projects. The rankings were prepared in accordance with previous BCUC instructions with criteria ranking being 1 to 5 with 1 being the lowest and 5 being the highest rank. Where possible for each criteria one alternative is ranked best and one the poorest. Where issues remain with all alternatives or where there are no meaningful differences between alternatives the rankings may be the same, or there may not be a best or poorest ranked alternative. The following criteria and definitions were used:

Definitions

1. **Reliability** - a measure of availability of electrical supply from the new transmission facilities. Also considers potential for exposure to damage and resulting service outages due to external hazards. For example, some line routes have higher exposure to wildfire, lightning and winter icing and are more difficult to access and repair, extending outage durations.

2. **Operations and Safety**

   a. **Operations** - considers accessibility and operability of the facilities by FortisBC employees and contractors working on system repairs or performing routine maintenance. An example is the degree of difficulty of access to transmission structures with heavy equipment.

   b. **Safety** - considers exposure to injury for persons working on or near line facilities including the general public, FortisBC employees, and contractors. Considerations include limits of approach to energized equipment and safe clearance for vehicles and service equipment. All facilities must be designed and maintained to the applicable safety standards.

3. **Public Health** - applies to known health and environmental issues posed by the transmission facilities, which may include but not be limited to, accidental release of controlled materials, oil spills, and any other such events. FortisBC designs, constructs and operates these facilities to ensure that probability of such events is mitigated. Health Canada has not determined that electric and magnetic fields, at levels associated with typical transmission lines, pose any hazard to public health. As some stakeholders have expressed concern, EMF has been considered separately (see item 10 below).

4. **Risk of Delay** - considers the risk of significant delay to the final in-service date of the proposed facilities. Delays can stem from regulatory process, permitting, zoning applications and procurement schedules.

5. **First Nations** - considers the effect of the Project on the cultural values, economic well being and quality of life of First Nations citizens.

6. **Environmental** - considers potential effects on the natural habitats of both aquatic and land dwelling plants and animals including rare and endangered species.

7. **Parks and Recreation** - considers the potential impact of the Project on the capability of the parks and recreation areas to continue to provide a quality experience for existing and future users.

8. **Aesthetics** - considers visual effects of the proposed facilities that may be observed by residents and visitors in the Project area.

9. **Property Values** - considers the potential effects of the proposed Project on the market value of real estate in the Project area.

10. **Electric and Magnetic Fields**– considers Project compliance with the International Commission on Non-Ionizing Radiation Protection (ICNIRP) reference levels for public exposure. All alternatives will be compliant with the reference levels. FortisBC has ranked the potential for EMF exposure based on proximity and frequency of passage expected on or immediately adjacent to the right-of-way.

11. **Effects during Construction** - considers the temporary disruption to residents, property owners and services near the Project area. Disruptions may include service interruptions, land use, traffic detours and delays, noise and dust.

Table 4-3-3D: Non Financial Comparison of Route Alternatives

(1 = lowest ranking: 5 = highest ranking)

	Criterion	Weighting Factors	Alternative 1A Existing Corridor – Single Pole Double Circuit		Alternative 1B Existing Corridor – H-Frame structure Double Circuit		Alternative 2A Upland - Single Pole Double Circuit		Alternative 2B Upland-Two Single Circuits		Alternative 3 Two Single Circuits – One Existing, One Upland	
			Rank	Weighted Rank	Rank	Weighted Rank	Rank	Weighted Rank	Rank	Weighted Rank	Rank	Weighted Rank
1	**Reliability**	**15**	4	60	4	60	2	30	3	45	5	75
2	**Operations and Safety**	**15**	3	45	3	45	1	15	3	45	4	60
3	**Public Health**	**10**	5	50	5	50	5	50	5	50	5	50
4	**Risk of Delay**	**15**	5	75	5	75	1	15	1	15	2	30
5	**First Nations**	**10**	4	40	4	40	2	20	2	20	2	20
6	**Environmental**	**10**	5	50	4	40	3	30	2	20	1	10
7	**Parks and Recreation**	**5**	4	20	4	20	4	20	4	20	2	10
8	**Aesthetics**	**5**	2	10	1	5	4	20	3	15	2	10
9	**Property Values**	**5**	5	25	5	25	5	25	5	25	5	25
10	**EMF**	**5**	4	20	3	15	5	25	5	25	3	15
11	**Effects during Construction**	**5**	1	5	1	5	3	15	3	15	1	5
12	**Totals**	**100**		**400**		**380**		**265**		**295**		**310**

4.3.4 Ranking Summary

In terms of non-financial criteria, Alternative 1A ranks highest overall, more so for the following criteria: Risk of Delay, First Nations and Environmental. It ranks lower in criteria where the route may impact existing developments near the line. It ranks higher than some of the Alternatives with respect to Reliability, Operations and Safety.

1. **Reliability** - The upland route alternatives have less expected reliability due to additional exposure to lightning strikes, wildfire, and winter ice impacting the lines due to the higher elevation of the route. The difficult higher elevation access also would mean that outage repairs would take longer. During winter months "valley cloud" would make aerial access to upland routes difficult at the 1,000 metre level. Alternative 3 ranks higher in reliability as the two separate routes provide path diversity for two-thirds of the distance from the Vaseux Lake Terminal station to RG Anderson Terminal station resulting in fewer events that would lead to double line outages.

2. **Operations and Safety** - The alternatives with the upland routes raise a number of operational and safety issues relating to line maintenance as well as emergency response time in the event of line damage requiring heavy or specialty equipment due to the limited or aerial access of the upland route. Due to the constraints imposed by the proposed Wildlife Management Area there will be minimal road access for maintenance purposes requiring more line access by helicopter. The alternatives with taller two circuit structures are more challenging to maintain. All Alternatives would be designed to current safety standards so there is little differentiation for public risk.

3. **Public Health** – All the line alternatives will be designed and operated to current standards and there is no scientific basis to distinguish between the alternatives based upon public health considerations.

4. **Risk of Delay** - Alternatives requiring new Crown Land rights-of-way increase the risks associated with Project delay due to the extended period for land

rights acquisition and regulatory approvals the outcomes of which are uncertain. Alternatives with new right-of-way construction will cause delays of 24 months or longer. The risk of Kelowna and Penticton area contingency power outage events would increase with each year of load growth. Alternative 3 might allow construction along the existing right-of-way while the securing new upland right-of-way partially reducing delay risks and costs.

5. **First Nations** - The upland alternate routes cross Crown Land that has traditional use areas of the First Nations and a pending claim to some land rights. Further consultation would be required to identify potential impacts. The existing right-of-way has several documented archeological sites nearby and construction planning has to include procedures to avoid disturbance of these sites. This is considered lesser impact than the Upland route.

6. **Environmental Factors** - The existing route has the smallest environmental footprint as it re-uses right-of-way that is already considered disturbed land and its re-use would be in keeping with Okanagan Shuswap Land Resource Management Plan Objectives and strategies. The alternatives using a new upland route will reduce some quality habitat used by a variety of species in a pristine setting including at risk bird species such as the Williamson's Sapsucker as well as the California Big Horn Sheep and other large mammals. Residual access after construction or for maintenance is a key concern as it may provide undesired public access into these pristine areas. Alternative 3 ranks the lowest due to its presence in both the existing and upland areas.

7. **Parks and Recreation** - The existing right-of-way is near to, but does not impact the climbing cliffs at Skaha Bluffs. The upland alternate routes cross areas where some guiding tenures are in place on the Crown Land. Alternative 3 is ranked lowest due to its presence in both the existing and upland areas.

8. **Aesthetics** – Approximately 2 kilometres of the existing right-of-way runs adjacent to nearby development resulting in a lower rank for Alternative 1A and 1B due to the taller poles and additional conductors. There would be some

mitigation by using non-glare conductors and aesthetic style poles for Alternative 1A versus 1B. The upland Alternatives 2A, 2B, and 3 may increase visibility of the right-of-way in some areas as it would climb uphill east of Shuttleworth Creek. Alternative 2A ranks the highest as it moves away from developed areas and has the smaller width right-of-way. Alternative 3 ranks the lowest by maintaining a presence in the developed areas of the existing right-of-way in addition to impacting the upland area.

9. **Property Values** - FortisBC does not consider any of the route alternatives to have a negative impact on area property market values, and as a result ranks all of the alternatives the same. Property values should not be considered in the final analysis of the route. For Alternative 1A and Alternative 1B the short and long term impact on property values due to the taller poles and additional conductors are difficult to assess in absolute terms. In the VITR Decision the Commission concluded that the VITR would not have a significant impact on average property values over the long term, and that any impact over the short term should be afforded little weight, because the proposal involved the use and upgrade of an existing right of way and transmission line.

This conclusion was reached in part due to the fact the VITR did not involve the addition of a transmission line where there currently was no line, and in consideration that the line was in place when the owners purchased their properties and thus had realized any benefit at the time of purchase. FortisBC contends that both of these factors are in place with the preferred OTR Project route alternative within the existing right-of-way.

FortisBC does not consider any perceived increase in value to properties near the existing right-of-way due to a move to a greenfield route to be germane to the decision as there is no benefit to either the Project or ratepayers in providing a potential advantage to a small group of landowners, especially when viewed in the wider Project prospective. FortisBC also submits that there is no general principle of universal application supporting a claim that the proposed OTR Project would have a negative impact on the value of any

property in the vicinity of this Project. The assessment is further supported by the Interwest Property Services Upland Route Analysis, which can be found in Appendix K.

10. **Electric and Magnetic Fields (EMF)** - All route line designs will meet the ICNIRP reference levels for public exposures. Magnetic fields for Alternatives 1A and 2A are predicted to reduce from the current existing levels. The compact double circuit lines considered for Alternative 1A and Alternative 2A will have the lowest magnetic fields due to cancellation effects of the configuration and the electric field will be less than the existing line due to structure height and location. Alternative 1B, due to it occupying more width of the right-of-way, ranks lower than Alternative 1A. Alternative 2A and Alternative 2B line routes, with no existing development near them, were also ranked higher due to less frequent human proximity.

11. **Effects During Construction** – Alternatives 1A, 1B and 3 using the existing right-of-way will have somewhat higher construction impact effects due to proximity of development along several kilometres of the route. No customer outages are expected to be needed for construction for any route alternatives. There will be helicopter and equipment activity in the area for all alternatives, more so for the upland routes. For all alternatives there would be work in the existing right-of-way to salvage the existing line conductors and poles.

4.3.5 Routing Conclusion

Selection of route and line configuration is a balance of numerous, often competing, considerations. Of the potential alternatives considered, Alternative 1A has the least environmental impact, minimizes visual impacts and has low cost and minimal delay risks due to the land rights already being in place. While Alternative 1B is the lowest cost and overall least cost option on the existing right-of-way, FortisBC does not believe that it is the most cost-effective alternative when consideration is given to the other OTR Project characteristics.

Response:

The Financial comparisons of Alternatives 1-4 are shown in Appendix 13. Please refer to BCUC IR 1.4.8 regarding Alternative 5.

The non-financial comparison of the Alternatives is as follows:

Definitions:

- Vulnerability
  - Takes into account potential for pipeline failure due to external hazards (Seismic event, river erosion, soil settlement (dike improvements)).

- Safety Concerns
  - Takes into account the risk to the public in the event of a pipeline failure
  - Takes into account the risk to TGI with respect to any scheduled maintenance or emergency repair work required.

- Environmental
  - Considers the level of impact during construction and post construction pipeline operations the alternatives have on the surrounding environment including off-shore activities, environmentally sensitive areas and agricultural land.

- Effect on Property
  - Takes into account the effect that the construction activities will have on any surrounding land owners, such as loss of business and land use restrictions.

- First Nations
  - Considers the effect of the project on the cultural values, economic well being and quality of life of First Nations citizens.

- Operational Flexibility
  - Considers the availability of a second pipeline crossing for O&M or emergency requirements.

- Post Earthquake Gas Load Capacity
  - Considers the ability to meet gas demand within the 20 yearr planning period, immediately following a strong seismic event (in which the pre-existing pipelines would fail).

(1 = Low; 3 = Moderate; 5 = High)

	Criterion	Weight	Alternative 1 - NPS 20 and 24 Replacement by HDD		Alternative 2 - NPS 24 Replacement by HDD		Alternative 3 - NPS 20 Replacement by HDD		Alternative 4 - NPS 30 HDD		Alternative 5 - NPS 36 HDD	
			Score	Weighted Score	Score	Weighted Score	Score	Weighted Score	Score	Weighted Score	Score	Weighted Score
1	Vulnerability											
	1.1 - Seismic	25	5	125	1	25	2	50	2	50	2	50
	1.2 - Erosion	10	5	50	1	10	4	40	4	40	4	40
	1.3 - Settlement (Dike)	2	5	10	2	4	2	4	2	4	2	4
2	Safety	20	5	100	1	20	1	20	2	40	2	40
3	Environmental	3	5	15	3	9	3	9	2	6	1	3
4	Effect on Property	4	5	20	4	16	4	16	2	8	2	8
5	First Nations	2	3	6	3	6	3	6	3	6	3	6
6	Operational Flexibility	4	5	20	4	16	4	16	2	8	2	8
7	Post Earthquake Capacity	30	5	150	2	60	1	30	5	150	5	150
8	**Totals**	**100**		**496**		**166**		**191**		**312**		**309**
9	**Ranking**			**1st**		**5th**		**4th**		**2nd**		**3rd**

Ranking Summary

The non-financial ranking matrix above shows Alternative 1 with the highest overall ranking. The rationale for each category is summarized as follows:

- Vulnerability
  - Seismic
    - Alternative 1 will meet the predicted TGI seismic criterion for risk of pipeline failure in a seismic event.
    - Alternatives 3, 4 and 5 will continue to have a pipeline in service that does not meet the predicted TGI seismic criterion for risk of pipeline failure in a seismic event.
    - Alternative 2 leaves an unimproved pipeline in service that does not meet TGI's seismic criterion, with an even higher risk of pipeline failure than Alternatives 3, 4 and 5.
  - Erosion
    - Alternative 1 will meet the predicted TGI erosion criterion for risk of pipeline failure due to river erosion.
    - Alternative 2 does meet the TGI criterion for river erosion.

- Alternative 3, 4 and 5 have less risk than Alternative 2, and currently meet the criterion for river erosion.

- Settlement
  - Alternative 1 mitigates the risk due to dike settlement.
  - Alternatives 2, 3, 4 and 5 contain risk due to settlement.

o Safety Concerns
- Alternative 1 meets TGI seismic criteria.
- The remaining NPS 20 pipeline in Alternative 2, and the NPS 24 pipeline in Alternatives 3, 4 and 5 pose a safety risk to the public which will require an emergency response.
- The remaining NPS 20 and 24 pipe in Alternatives 2 and 3 will in addition require a pipeline repair and increased maintenance activities.

o Environmental
- Alternative 1 has an equivalent footprint to Alternatives 2 and 3 and requires no future maintenance or improvements
- Alternatives 4 and 5 will require much larger on-shore footprints to complete the work.
- Alternatives 2 and 3 may require future maintenance and repair work in sensitive areas.

o Effect on Property
- Alternative 1 will have a longer continuous construction impact but the footprint will be far smaller than Alternatives 4 and 5. Alternative 1 also eliminates the need for future upgrades.
- Alternatives 2 and 3 have less construction impact but will likely require future repair and maintenance work.
- Alternatives 4 and 5 will impact more agricultural and industrial land, resulting in greater potential loss or disruption.

o First Nations
- All Alternatives equally minimize or avoid any impact with First Nations.

o Operational Flexibility
- All Alternatives will provide pre-seismic non-peak operational flexibility with two lines operating under the river.
- After a pipeline failure, only alternative 1 maintains this flexibility without further work.

- Alternatives 2 and 3 will retain this flexibility after the failed pipeline is replaced.

- Alternatives 2 and 3 will also require ongoing monitoring for river erosion and dike settlement, resulting in potential future repair work.

o Post Earthquake Capacity

- Alternatives 1, 4 and 5 will meet future gas load requirements in the result of a seismic event for the 20 year long range planning period.

- Alternatives 2 and 3 do not immediately meet the future gas load requirements in the event of a failure.

12.0 Reference: Exhibit B-1, p. 37, and Appendix 12

"Based on forecasted volumes for sales and applicable transportation customers the unit cost of service impact is estimated to be 1.4 cents per GJ starting 2010 (B-1, p. 37)."

12.1 What is the date of the volume forecast series on which the above calculation was based?

The volume forecast is based on the same data and assumptions used in the preparation of the 2008 TGI Annual Review Advance Materials dated October 8, 2008. The first year impact of 1.4 cents per GJ is based on forecasted volumes for sales and applicable transportation customers in 2010 assuming the Project is completed by the end of 2009. To the degree that final costs, customer use rates or customer account numbers differ from the assumptions used in the Application used this impact will be slightly different but not significantly so. In addition, as the new facilities depreciate the cost of service impact will decrease over time.

Note that the forecasted volumes used were for total sales and transportation service customers, less bypass transportation service customer volumes. However, non-bypass volumes were subtracted in error instead of bypass volumes which resulted in a slight change to the Cost of Service calculation provided in the Application. The cost of service impact is still estimated to be 1.4 cents per GJ starting in 2010. A revised Appendix 12 Cost of Service Impact follows.

Appendix 12 Revised - Fraser River South Arm Upgrade Project Cost of Service Impact ($000)

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Incremental Mid-Year Rate Base	**$26,831**	**$26,493**	**$25,955**	**$25,417**	**$24,879**	**$24,341**	**$23,803**	**$23,265**	**$22,727**	**$22,189**
Incremental Cost of Service										
Depreciation Expense New Facilities	$538	$538	$538	$538	$538	$538	$538	$538	$538	$538
Avoided Depreciation Expense Retired Facilities	($42)	($42)	($42)	($42)	($42)	($42)	($42)	($42)	($42)	($42)
Income Tax Expense	($324)	($244)	($178)	($120)	($72)	($37)	($5)	$24	$50	$73
Earned Return on Rate Base	$2,007	$1,982	$1,941	$1,901	$1,861	$1,821	$1,780	$1,740	$1,700	$1,660
Total Cost of Service	**$2,179**	**$2,234**	**$2,259**	**$2,278**	**$2,285**	**$2,280**	**$2,271**	**$2,260**	**$2,246**	**$2,229**
Unit Cost of Service Impact										
Sales and Applicable Transportation Volumes (PJ/Yr)	153	156	158	160	163	165	167	169	172	174
Unit Cost of Service ($/GJ)	**$0.014**	**$0.014**	**$0.014**	**$0.014**	**$0.014**	**$0.014**	**$0.014**	**$0.013**	**$0.013**	**$0.013**

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Incremental Mid-Year Rate Base	**$21,651**	**$21,113**	**$20,575**	**$20,037**	**$19,499**	**$18,961**	**$18,423**	**$17,885**	**$17,347**	**$16,809**
Incremental Cost of Service										
Depreciation Expense New Facilities	$538	$538	$538	$538	$538	$538	$538	$538	$538	$538
Avoided Depreciation Expense Retired Facilities	($42)	($42)	($42)	($42)	($42)	($42)	($42)	($42)	($42)	($42)
Income Tax Expense	$94	$114	$131	$146	$159	$171	$182	$191	$199	$206
Earned Return on Rate Base	$1,619	$1,579	$1,539	$1,499	$1,459	$1,418	$1,378	$1,338	$1,298	$1,257
Total Cost of Service	**$2,210**	**$2,189**	**$2,166**	**$2,141**	**$2,114**	**$2,086**	**$2,056**	**$2,025**	**$1,993**	**$1,960**
Unit Cost of Service Impact										
Sales and Applicable Transportation Volumes (PJ/Yr)	176	178	181	183	186	188	191	193	196	198
Unit Cost of Service ($/GJ)	**$0.013**	**$0.012**	**$0.012**	**$0.012**	**$0.011**	**$0.011**	**$0.011**	**$0.010**	**$0.010**	**$0.010**

Based on TGI current approved 64.99% - 35.01% debt equity structure, 8.62% ROE and 8% CCA rate.
Unit cost of service impact based on forcasted sales volumes and non-bypass transportation service volumes.
All costs presented in $2008

12.2 Does the volume forecast differ from the TGI demand forecast presented in the 2008 TGI Resource Plan? If so, why?

Response:

Yes, the volume forecast used was the most recent available at the time of preparation of the Application and was based on more recent data than the data used in early 2008 to prepare the 2008 Resource Plan forecast.

The 2008 Resource Plan volume forecast included all TGI volumes. Volumes for TG Fort Nelson and the bypass industrial transportation customers are not applicable to the unit cost of service impact. For comparison purposes, the 2008 Resource plan volumes less the TG Fort Nelson and the industrial bypass transportation volumes are compared with the volumes from the Application in the table below.

2008 TGI Resource Plan Volumes (PJ)						Application
Year	Coastal	Interior	Total	Bypass & Ft Nelson	Net	Volumes (PJ)
2010	121	57	178	15	163	153
2011	121	57	179	15	164	156
2012	122	58	180	14	166	158
2013	122	59	181	14	167	160
2014	123	59	182	14	168	163

As displayed in the table, the volume forecast used in the Application is lower than the one used in 2008 Resource Plan. Using the 2008 Resource Plan volumes, the resulting unit cost of service impact is slightly less, at 1.3 cents per GJ starting 2010.

13.0 Reference: Exhibit B-1, pp. 15, 16, 18, and 19

13.1 At what future time will expected demand growth in the region require a capacity increase beyond that provided by the NPS 20 and NPS 24 lines across the South Arm of the Fraser River?

Response:

A capacity increase beyond that provided by the NPS 20 and NPS 24 lines across the South Arm of the Fraser River is not required in the long term. See responses to BCUC IR 1.4.1 and 1.4.11.

13.2 Does Alternative 1 include the salvage of the existing lines or their abandonment? If the lines are to be salvaged, what is their salvage value?

Response:

Alternative 1 includes the abandonment of the existing river crossing pipelines, as per CSA Z662 Clause 10.17, with no salvage value. TGI is not anticipating any salvage value for the abandoned lines.

13.3 At what future time would expected regional demand growth require a capacity increase beyond that provided by Alternative 4's NPS 24 and NPS 30 lines across the South Arm of the Fraser River?

Response:

As discussed in the response to BCUC IR 1.4.1, there is no capacity increase required for the combination of a NPS 24 and NPS 30 crossings beyond a 50-year period.

14.0 Reference: Exhibit B-1, pp. 32, 33, and Appendix 11

"TGI has contacted three First Nations who have archaeological interests in the area - Tsawwassen First Nation, Katzie First Nation and Musqueam First Nation - and provided information on the proposed project. To date none of the three First Nations have identified any issues with the project (B-1, p. 32)."

"With respect to First Nations, in light of the limited impact to previously disturbed fee simple land, TGI believes that the consultation conducted to date has been appropriate and adequate (B-1, p. 33)."

14.1 Appendix 11 shows that, although information has been sent to the three First Nations, Terasen is yet to receive response communications from them. Please explain whether Terasen believes that the absence of a response is indicative of acceptance by the First Nations.

Response:

Terasen Gas has communicated an overview and provided documents of the proposed Project to the three First Nations for their information (see BCUC IR 1.14.2). TGI is of the view that, in light of the limited impacts, the fact that the Project is on private land and the small footprint associated with this Project, the consultation conducted to date is adequate and appropriate.

The three First Nations have, in the past, shown no reluctance to voice concerns about projects in response to requests relating to projects. Although Terasen Gas is not suggesting that the absence of a response from the three First Nations means they have consented to the Project, Terasen notes that consultation obligations do not convey to First Nations a veto over projects. In the circumstances, an affirmative response from these First Nations is not a requirement for the granting of a CPCN or to proceed with the Project.

14.2 Please provide copies of the letters and maps that were sent to the Tsawwassen, Katzie, and Musqueam First Nations, as referred to in Appendix 11.

Response:

Copies of the documents sent to the Tsawwassen, Katize and Musqueam First Nations can be found in the appendices of the Application. Copies of the letters are enclosed in Appendix 11 and the map is in Appendix 6.

14.3 Please explain whether Terasen did in fact meet with Arlene H. Henry, QC, as per Appendix 11.

Response:

Yes, Terasen Gas met with Ms. Arlene H. Henry, QC and Mr. Richard J. Jackson on August 07, 2008 at the law offices of STIKEMAN ELLIOTT LLP Barristers & Solicitors in Vancouver.

The meeting agenda included a status report by Ms. Henry on the Tsawwassen First Nation ("TFN") and its Final Agreement implementation to each affected utility and third party interests and whether TFN had any interest outside of their settlement area. Terasen Gas was verbally informed that TFN has no interest beyond their lands and a full and final settlement had been reached.

15.0 Reference: Exhibit B-1, Table 6.1 and Appendix 13, and 2008 TGI Resource Plan, Appendix J, p. J1-9

"In 2006, an engineering assessment of the current 20" and 24" underwater Transmission pipeline crossings of the South Arm of the Fraser River serving Vancouver and Richmond was completed. The engineering assessment provided an opinion indicating that both the underwater crossings and the adjacent south bank require extensive rehabilitation to ensure they do not pose a risk in the event of a seismic occurrence. Terasen Gas has recently received a second opinion on the matter, which confirms that rehabilitation work is necessary. Terasen Gas anticipates that it will file a CPCN application for this project towards late 2008 targeting an expected completion date of the project in 2009. Project costs are currently estimated to be $9.75 million (excluding AFUDC) (2008 TGI Resource Plan, Appendix J, p. J1-9)."

15.1 The Application's Table 6.1 and Appendix 13 list the components of the estimated project costs--including an estimate for AFUDC of $0.9 million. Please explain the reasons for the difference between the 2008 Resource Plan estimated cost of $9.75 million and the Application's estimate of $27.3 million.

Response:

The differences between the 2008 Resource Plan with an estimated cost of $9.75 and the Applications estimate of $27.3 are attributable to the following reasons:

- The 2008 Resource Plan was developed in anticipation of achieving the recommendations as summarized in the 2007 Golder Report, and assumed replacing the NPS 20 crossing only. Subsequent to the preparation of the Resource Plan, and as preparatory design work to implement the recommendations, the 2008 Golder Report was commissioned. The 2008 Report resulted in a change to the river crossing upgrade recommendations and the Application proposes to replace both the NPS 20 and NPS 24, based on updated studies and evaluation.

- The two cost estimates use different bases:

  - The Application estimate was prepared against a preliminary construction plan to meet the Project goals.

  - The 2008 Resource Plan estimate used a conceptual description of the scope of work and assumed historical high-level percentage breakdowns of major Project cost components are proportionate.

- The 2008 seismic evaluation requires that the replaced crossings be longer and to a greater depth than assumed for the estimate for the 2008 Resource Plan.

- Temporary bypass lines around the drill entry and exit sites are included in the Application to maintain system delivery while constructing the two pipelines replacements.

- Material pricing for the Application estimate is based on preliminary vendor estimates for pipe properties designed to fit the seismic model.

- In the Application, the HDD installation contractor costs are based on the recent experience of TGI's HDD Engineering & Construction Consultant, and the Resource Plan estimate was based on historical quotations.

- Retirement Costs and AFUDC costs are estimated in the Application.

- A Dike Improvement Allowance is included in the Application based on updated studies.

16.0 Reference: Exhibit B-1, p. 30

"The HDD contractor and the major materials, such as pipe and valves, will be procured from out-of province sources since these resources are not available in B.C."

16.1 How much, if any, of the expected project costs is anticipated to be provided by suppliers and/or contractors requiring payment in U.S. dollars?

Response:

TGI does not anticipate suppliers and/or contractors to require payment in U.S. dollars.

17.0 Reference: Exhibit B-1, p. 2

17.1 Please summarize TGI's technical capability with respect to river crossings and HDD.

Response:

TGI has engineered and constructed major water body crossings with HDD since 1991. TGI has utilized HDD on 26 major water crossings, and performed engineering studies on many more. Small and intermediate HDD river, highway, and railroad crossings are now routinely engineered and constructed to TGI Standards. External engineering and construction consulting expertise is utilized as needed, and has been retained for this Project due to its scope.

18.0 Reference: Exhibit B-1, pp. 14 et seq

18.1 Please provide an economic analysis (in fully functioning Excel spreadsheet format) of the 4 HDD alternatives considered and a "status quo" scenario and derive the PV of the cash flows of the 5 scenarios. Consider the following:

- Incremental cash flows (ignore items such as allocated cost and interest);
- Discount rate: Incremental WACC;
- Term: up to 50 years;
- Assumptions may include:
- "Status quo:" Replace NPS 20 and NPS 24 at the end of their useful lives using HDD, estimate costs to mitigate erosion vulnerability and of dike settlement;
- Replace NPS 24: Replace NPS 20 at the end of its useful life using HDD, estimate costs to mitigate erosion vulnerability and of dike settlement;
- Replace NPS 20: Replace NPS 24 at the end of its useful life using HDD, estimate costs of dike settlement;
- Replace NPS 20 with new NPS 30: Replace NPS 24 at the end of its useful life using HDD, estimate costs of dike settlement;

Response:

See Attachment 18.1 for the economic analysis in fully functioning excel format. The Alternatives summarized in the table below are based on those included in the Application, but are modified to include the assumptions in this Information Request.

In order to provide a response to this question, an assumption must be made about when each of the existing crossings reaches "the end of its useful life". The original NPS 20 crossing was installed in 1958 and the NPS 24 crossing was installed in 16 years later in 1974. Since that time there have been capital upgrades and expenditures to protect and to extend the life the crossings. As discussed in the response to BCUC IR1.3.2, recent internal line inspections indicate that the crossings are in relatively sound condition therefore in the absence of the concerns related to seismic reliability, erosion and dike settlement it would be difficult to estimate when the crossings would otherwise need to be replaced.

For the purposes of this response, therefore, it is assumed that the end of the useful life for each crossing is 60 years, and that in the absence of this Project the NPS 20 would otherwise be replaced in 2018, and the NPS 24 replaced 16 years later in 2034. Note that this is an assumption for the purpose of this response only and to directionally

demonstrate the financial impact of deferring the replacement of the one or both crossings.

The future replacement capital costs of the NPS 20 and NPS 24 pipeline crossings were assumed to be the capital costs in the Application escalated annually at 2% until the year of replacement. The discount rate applied to calculate the present value was 7.48% based on the approved 2008 ROE, cost of debt and capital structure. The estimated direct cost to mitigate erosion is expected to be in the range of $5 million to $10 million and would be incurred in the period of 2009 through 2013. For this analysis the capital cost is assumed to be $7.5 million during the period.

Alternative	**PV ($m)**
"*Status quo*:" Replace NPS 20 and NPS 24 in 2018 and 2032 respectively using HDD, estimate costs to mitigate erosion vulnerability and of dike settlement	19.7
Alternative A: Replace NPS 20 and NPS 24 now using HDD as proposed in the Application.	26.8
Alternative B: Replace NPS 24 immediately. Replace NPS 20 in 2018 using HDD, estimate costs to mitigate erosion vulnerability and of dike settlement	32.9
Alternative C: Replace NPS 20: Replace NPS 24 in 2034 using HDD, estimate costs of dike settlement	19.8
Alternative D: Replace NPS 20 with new NPS 30: Replace NPS 24 in 2032 life using HDD, estimate costs of dike settlement	29.9

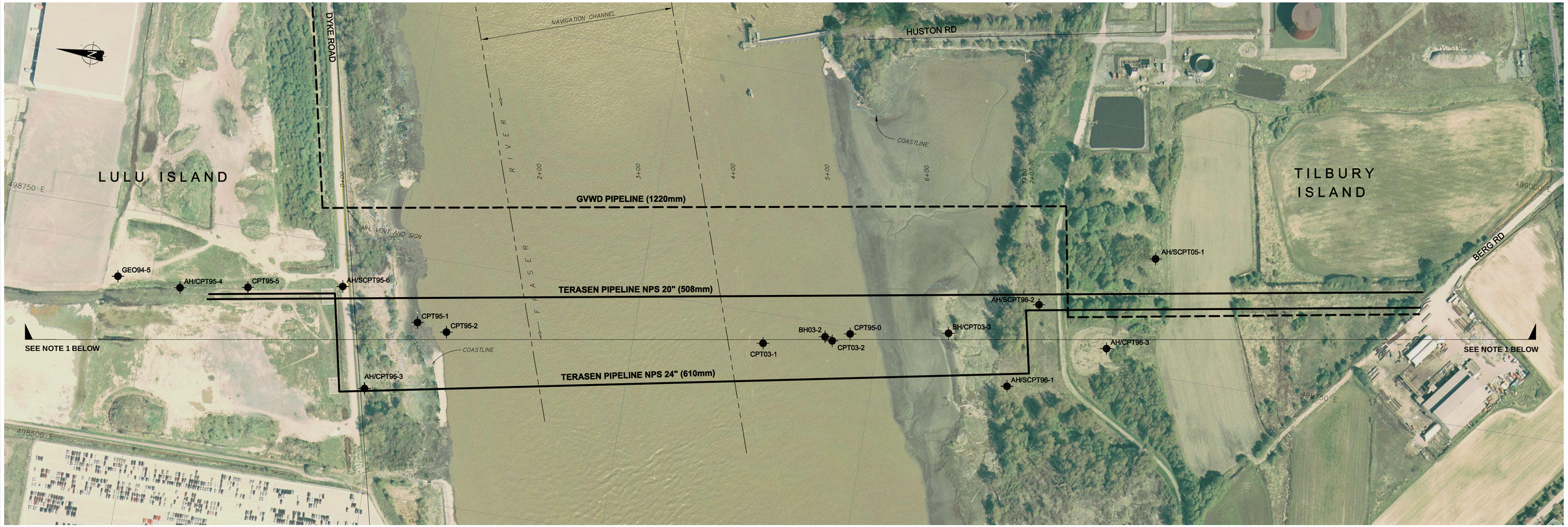
19.0 Reference: Exhibit B-1, Table 6.2 and Appendix 7

19.1 In the event that the required permits take more than 6 months to obtain, with actual construction then possible only at the start of August 2009, would TGI intend to commence construction at that date, or defer commencement until 2010? If deferring to 2010, what month would construction commence?

Response:

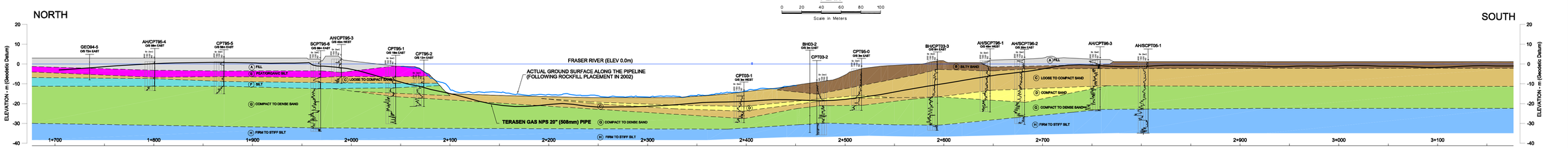
TGI anticipates the permitting for the HDD river crossing replacements to follow existing and routine permit application processes. TGI has not identified regulatory permitting processes for the Project that requires an extended timeline. In the event that predecessor activities such as receipt of permits have not been completed by July 2009 or later, and if consequently TGI forecasts that achieving a November 1, 2009 in-service milestone for both pipelines is substantially unlikely to occur, and adverse impacts cannot be mitigated, then TGI would defer the entire mainline construction phase to start on, or about, May 2010.

Attachment 1.3

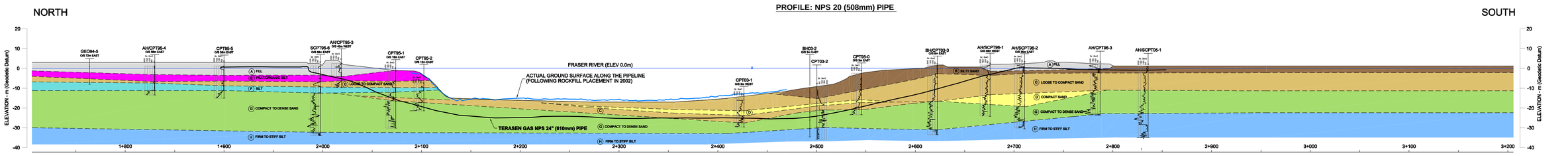


PLAN

0 20 40 60 80 100
Scale in Meters



PROFILE: NPS 20 (508mm) PIPE



PROFILE: NPS 24 (610mm) PIPE

0 20 40 60 80 100
Horizontal Scale in Meters
0 10 20 30 40 50
Vertical Scale in Meters

LEGEND

- A - FILL
- B - SILTY SAND
- E - PEAT/ORGANIC SILT
- F - SILT
- C - LOOSE TO COMPACT SAND
- D - COMPACT SAND
- G - COMPACT TO DENSE SAND
- H - FIRM TO STIFF SILT
- APPROXIMATE LOCATION OF TEST HOLES

NOTES

1. Interpreted stratigraphic profiles were developed at section line shown in above plan. The actual ground surface profiles above the pipelines within the river (following rip rap placement in 2002) are shown in the profiles.
2. The pipeline profiles shown were derived from GEOPIG pipeline measurements. These profiles are superimposed on the interpreted stratigraphic profiles and are therefore approximate.
3. Data concerning the various strata have been obtained at test hole locations only. The soil stratigraphy between test holes has been inferred from geological evidence and so may vary from that shown.

REFERENCES

1. Hay & Company Consultants Inc. / Fraser River Pile & Dredge Ltd.
   File: BCGS-003A (Rev B)
   Dated: Mar. 2002
2. BC Gas
   Dwg No.: 42012-P-000-105-1-0 (Rev 3)
   Dated: 17 Apr. 2003
3. BC Gas
   Dwg No.: 42013-P-000-105-1-0 (Rev 0)
   Dated: May 1998

PROJECT

TERASEN GAS INC.
NPS 20 & 24 T.P. PIPELINE
SOUTH ARM-FRASER RIVER, DELTA/RICHMOND, B.C.

TITLE

SITE PLAN AND INTERPRETED STRATIGRAPHIC PROFILE

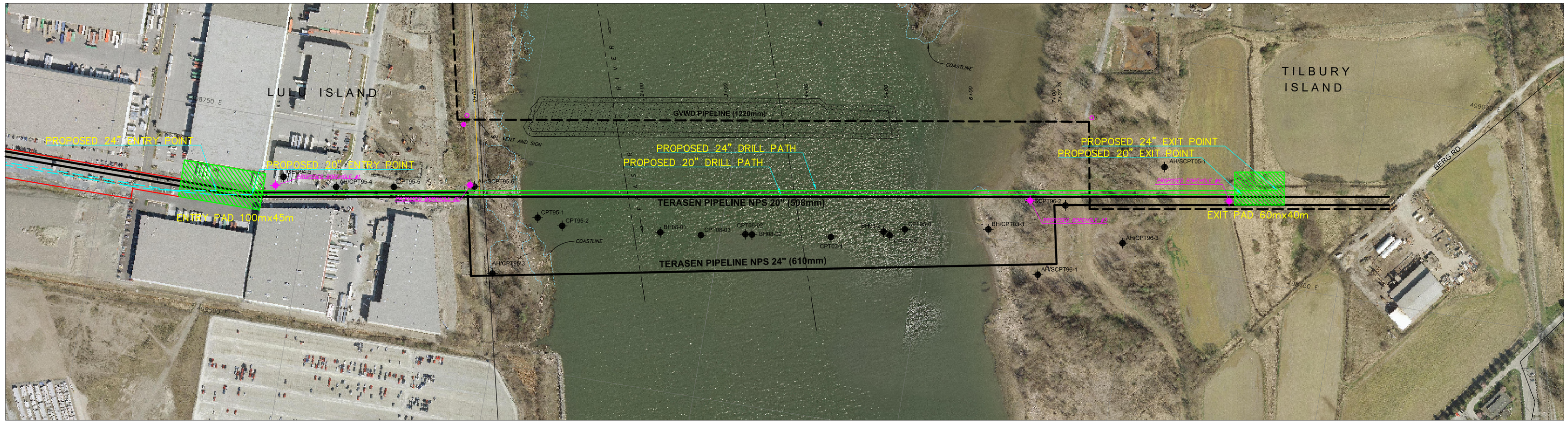
Golder Associates

PROJECT No.	03-1411-050		FILE No.	P1411-505-5
DESIGN	MK	15FEB06	SCALE	AS SHOWN REV. –
CADD	SRR	15FEB06		
CHECK	MK	15FEB06		
REVIEW	MTB	21FEB06		

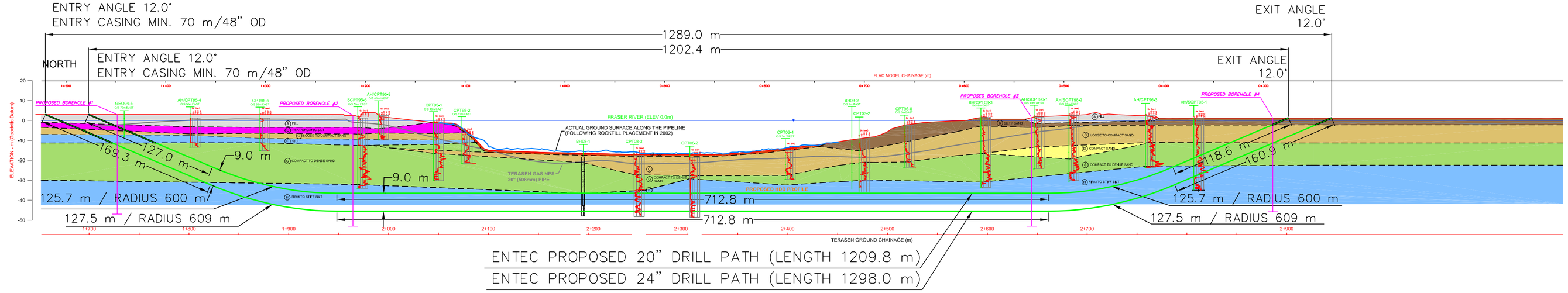
FIGURE 2-1

REVISION DATE: 07/09/09 03:13PM By: MKennedy CASD FILE: O:\Active\2003\1411\03-1411-050 BC Gas South Bank-South Arm\August 2007 Summary for Terasen & BCG\Figure 2-1\P1411-050-5.dwg

Drawing File: P1411-050-5.dwg Dec 12, 2008 - 2:41pm



PLAN VIEW SCALE 1:2500



PROFILE VIEW SCALE H 1:2500 V 1:1250

PRELIMINARY

PERMIT

SEAL/STAMP

NOTES

GROUND PROFILE, SURVEY DATA, PHOTOMOSAIC AND GEOTECHNICAL INFORMATION PROVIDED IN GOLDER REPORT 08-1411-0010. PHOTOMOSAIC APRIL 2008

DESIGN SPECIFICATIONS

								0D	2008/11/10	MOVED PIPE LAYOUT TO NORTHSIDE, ADDED 24" DESIGN TO PROFILE VIEW	IR		
								0C	2008/06/24	ADD PIPE LAYOUT PLAN, MOVE EXIT NORTH 35 m, CHG. ENTRY WORK SPACE	DL	DL	JJ
1	NPS 24	12.7 mm	STEEL	483 MPa	4020 kPa	5'C	???	0B	2008/05/15	UPDATE GEOTECH AND SURVEY DATA, ADDED WORKSPACES AND PIPE LAYOUT	ML	DL	JJ
1	NPS 20	12.7 mm	STEEL	448 MPa	4020 kPa	5'C	???	0A	2008/05/06	PRELIMINARY DESIGN	ML	DL	
QTY	PIPE O.D.	W.T.	MATERIAL	GRADE	M.O.P.	M.O.T.	TEST PRES.	NO.	DATE	REVISION DESCRIPTION	DR.	CHK.	APPR.

Engineering Technology Inc.
Suite 24, 12110 - 40 St SE
CALGARY, ALBERTA T2Z 4K6
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www.entecinc.com

Golder Associates

Terasen Gas

TERASEN GAS
FRASER RIVER – SOUTH ARM
NPS 20/ NPS 24 DIRECTIONAL DRILL PROFILE
DELTA/RICHMOND B.C.

SHEET SIZE ARCH D

SCALE AS SHOWN

REV. 0D

DRAWING NUMBER

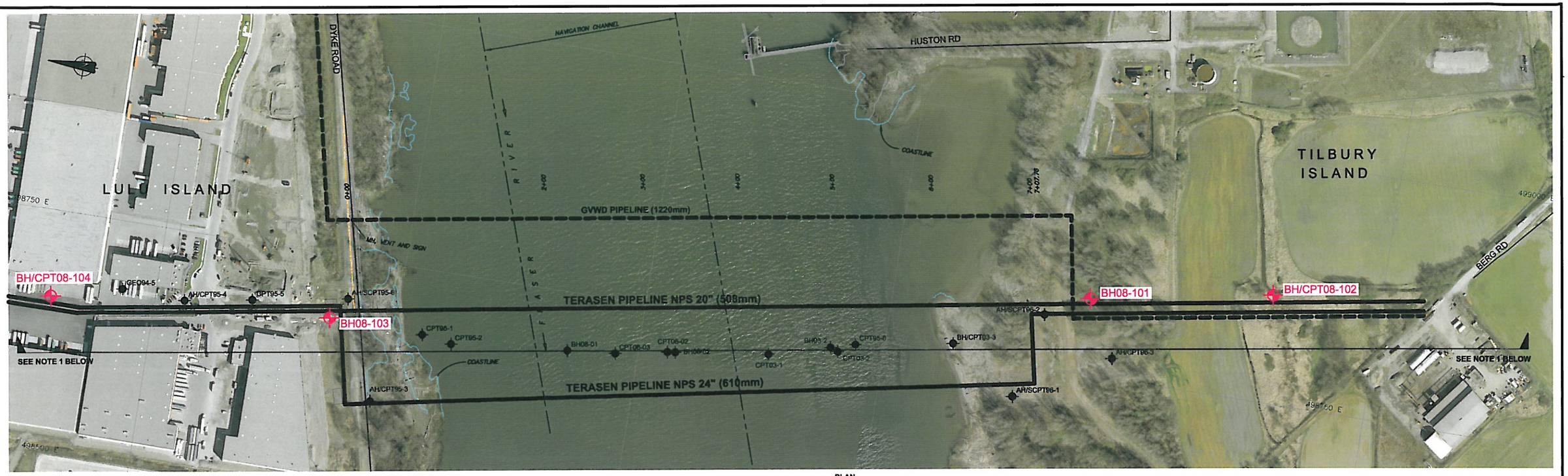
337 TERASEN FRASER RIVER

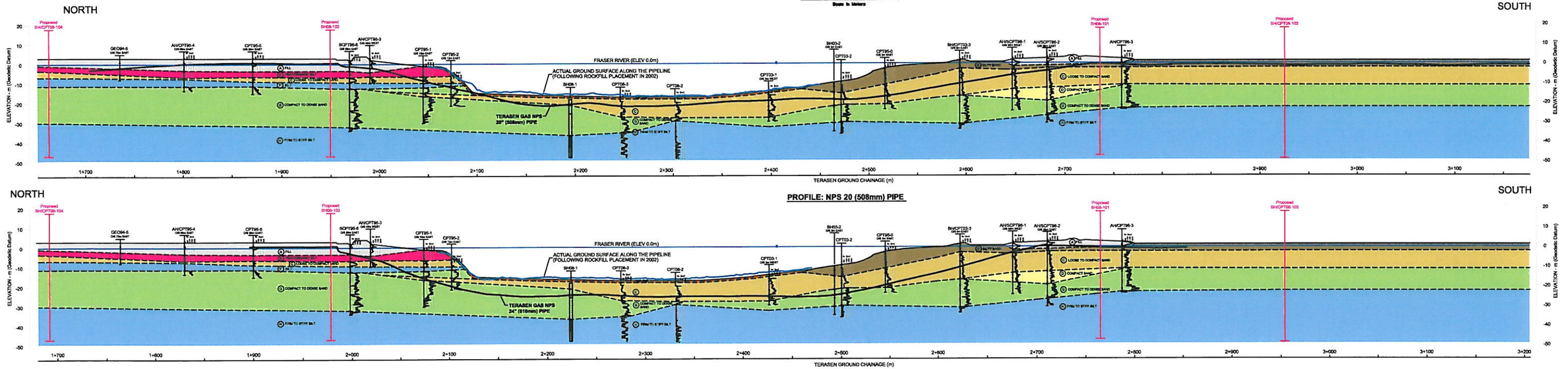
SHT.No. 1/1

PLOT SCALE:1:1

SAVE NAME: 337 TERASEN FRASER RIVER REV 0D

Attachment 6.4





LEGEND

- A - FILL
- B - SILTY SAND
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- F - SILT
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- D - COMPACT SAND
- G - COMPACT TO DENSE SAND
- H - FIRM TO STIFF SILT
- APPROXIMATE LOCATION OF TEST HOLES
- PROPOSED TEST HOLE LOCATIONS (DEC 2008)

NOTES

1. Interpreted stratigraphic profiles were developed at section line shown in above plan. The actual ground surface profiles above the pipelines within the river (following rip rap placement in 2002) are shown in the profiles.
2. The pipeline profiles shown were derived from GEOPIG pipeline measurements. These profiles are superimposed on the interpreted stratigraphic profiles and are therefore approximate.
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1. Hay & Company Consultants Inc. / Fraser River Pile & Dredge Ltd. File: BCGS-003A (Rev B) Dated: Mar. 2002
2. BC Gas Dwg No.: 42012-P-000-105-1-0 (Rev 3) Dated: 17 Apr. 2003
3. BC Gas Dwg No.: 42013-P-000-105-1-0 (Rev 0) Dated: May 1998
4. McElhanney 2008 orthophoto.

PROJECT
TERASEN GAS INC.
NPS 20 & 24 T.P. PIPELINES
SOUTH ARM-FRASER RIVER, DELTA/RICHMOND, B.C.

TITLE
SITE PLAN AND INTERPRETED STRATIGRAPHIC PROFILE

Golder Associates

PROJECT No. 08-1411-0010			FILE No.		
DESIGN	VF	11JUN08	SCALE	AS SHOWN	REV. –
CADD	MJK	08DEC08			
CHECK					
REVIEW					

FIGURE 1

CADD FILE: G:\Golder_2008\1411\08-1411-0010 Terasen Gas South Arm Fraser River\2008 - Develop HDD Concepts\08141110010-3000 A_fig0-1.dwg
REVISION DATE: 08/12/08 01:12PM By: MKennedy

TABLE 1: Update Summary of Subsurface Data

Year	Test Hole	Depth (m)	Driller	Consultant
1995	CPT95-0	21.0	ConeTec Investigations Ltd.	Golder
1995	CPT95-1	28.7	ConeTec Investigations Ltd.	Golder
1995	CPT95-2	13.8	ConeTec Investigations Ltd.	Golder
1995	AH/CPT95-3	4.0/12.3	ConeTec Investigations Ltd.	Golder
1995	AH/CPT95-4	13.3/14.7	ConeTec Investigations Ltd.	Golder
1995	CPT95-5	16.3	ConeTec Investigations Ltd.	Golder
1995	AH/SCPT95-6	16.8/35.2	ConeTec Investigations Ltd.	Golder
1996	AH/CPT96-1	15.2/25.8	ConeTec Investigations Ltd.	Golder
1996	AH/SCPT96-2	15.2/32.7	ConeTec Investigations Ltd.	Golder
1996	AH/CPT96-3	15.2/26.0	ConeTec Investigations Ltd.	Golder
2003	CPT03-1	14.6	ConeTec Investigations Ltd.	Golder
2003	CPT03-2	26.7	ConeTec Investigations Ltd.	Golder
2003	BH03-2	25.0	Mud Bay Drilling Co. Ltd.	Golder
2003	BH/CPT03-3	21.3/35.1	Mud Bay Drilling Co. Ltd./ ConeTec Investigations Ltd.	Golder
2008	BH08-1	29.6	Mud Bay Drilling Co. Ltd.	Golder
2008	BH/CPT08-2	15.9/30.1	Mud Bay Drilling Co. Ltd./ ConeTec Investigations Ltd.	Golder
2008	CPT08-3	30.6	ConeTec Investigations Ltd.	Golder
2008	BH08-101	50	Mud Bay Drilling Co. Ltd.	Golder
2008	BH/CPT08-102	50/50	Mud Bay Drilling Co. Ltd./ ConeTec Investigations Ltd.	Golder

TABLE 1: Summary of Subsurface Data (cont'd)

Year	Test Hole	Depth (m)	Driller	Consultant
2008	BH08-103	50	Mud Bay Drilling Co. Ltd.	Golder
2008	BH/CPT08-104	50/50	Mud Bay Drilling Co. Ltd./ ConeTec Investigations Ltd.	Golder

Attachment 18.1

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)