FORTIS BC™

Diane Roy
Director, Regulatory Services

Gas Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

March 12, 2015

Via Email
Original via Mail

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Inc. (FEI)

Application for a Certificate of Public Convenience and Necessity (CPCN) for Approval of the Lower Mainland Intermediate Pressure (IP) System Upgrade (LMIPSU) Projects (the Application)

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 1

On December 19, 2014, FEI filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-1-15 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to CEC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc: Commission Secretary
Registered Parties (e-mail only)

1.0 Reference: Exhibit B-1, Page 1

> FEI is also seeking Commission approval under sections 59-61 of the Act for deferral treatment of costs for preparing this Application, and therefore requests a new deferral account, entitled the "LMIPSU Application Costs deferral account". The LMIPSU Application costs would be included in Rate Base and amortized over a three year period commencing January 1, 2016. The Application costs include expenses for legal review, consultant costs[2], Commission costs and Commission approved intervener costs, and forecast costs to support the hearing process.
>
> The LMIPSU application costs will be recorded in a Non-Rate Base deferral account on a net-of-tax basis attracting a weighted average after tax cost of capital (WACC) return until December 31, 2015. The balance of the LMIPSU Application Costs deferral account as at December 31, 2015, is forecast to be $1.047 million.[3]
>
> [1] In some Appendices completed by third parties and in some public information documents completed early in the planning phase, the Coquitlam Gate IP Project was referred to as the Metro IP Project; however the Metro IP includes both the Coquitlam Gate IP system and the Fraser Gate IP system whereas the Coquitlam Gate IP Project only includes the Coquitlam IP system.
>
> [2] For assistance in answering information requests.
>
> [3] Approximately $1.387 million on a before tax basis, this includes $80 thousand financing charges at the Company's weighted average cost of capital.

1.1 What are the total estimated consultant costs?

Response:

Please refer to the response to BCUC IR 1.51.1.

1.1.1 Please break-down by consultant if possible.

Response:

The following table provides a breakdown of the forecast Consultant and Contractor Fees as provided in the response to BCUC IR 1.51.1. This breakdown is provided by general category of consultation.

Forecast Consultant & Contractor Fees, $ Thousands

Line	Cost Component	Total
1	Engineering	$ 110
2	Environmental & Archaeological	6
3	Stakeholder Engagement	27
4	Property Services	28
5	Regulatory Support	162
6	**Total External Consultant & Contractor Fees**	332
7	Internal Engineering & Project Management	138
8	**Total Consultant & Contractor Fees**	**$ 471**

1.2 Please confirm or otherwise explain that the LMIPSU Application Costs only include BCUC related costs, and do not include regulatory costs associated with approvals from other regulators such as the OGC.

Response:

Confirmed. .

2.0 Reference: Exhibit B-1, Page 2

> Also under sections 59-61 of the Act, FEI is further seeking approval from the Commission to record in a new deferral account, entitled the "LMIPSU Project Development account", project development costs that cover expenses for project management, engineering, and consultants' costs for assessing the potential design and alternatives and associated costs prior to Commission approval of the Projects. The LMIPSU Project Development costs would be included in Rate Base and FEI will begin to amortize these costs over three years starting January 1, 2016. The LMIPSU Project Development costs will be recorded in a Non-Rate Base deferral account on a net-of-tax basis attracting a weighted average after tax cost of capital (WACC) return until December 31, 2015. The balance in this account at December 31, 2015, is forecast to be $2.004 million.[4]

2.1 What are the total project development costs that have been incurred to date?

Response:

The total project development costs that have been incurred to January 31, 2015 are $2.433 million as-spent dollars.

2.2 What will happen if the project is still in the Project Development stage as of December 31, 2015?

Response:

The Company does not anticipate continuing to be in the Project Development stage as of December 31, 2015. Project Development work is almost complete except for work being done for the Lougheed Highway route option and Project scope optimization related to the amount of pipeline to be replaced at Fraser Gate. Subject to further work potentially required due to Commission directions, no additional costs would be charged to the Project Development deferral account except financing charges at the Company's after-tax WACC while the Project Development deferral costs remain out of Rate Base.

Please also refer to the response to CEC IR 1.33.4.

3.0 Reference: Exhibit B-1, Page 2

> The Coquitlam Gate IP pipeline portion of these Projects will install approximately 20 kilometres of NPS 30 Coquitlam Gate IP pipeline operating at 2070 kPa and extending from Coquitlam Gate station (Coquitlam Gate) at Mariner Way & Como Lake Avenue in Coquitlam to East 2nd & Woodland Drive in Vancouver (2nd & Woodland) (Coquitlam Gate IP pipeline). This pipeline will replace an existing NPS 20 pipeline operating at 1200 kPa that is nearing the end of its service life as evidenced by the increasing frequency of gas leaks resulting from non-preventable active corrosion. It has been determined, based on field observations during pipeline excavations and leak responses that failure of the field-applied coating installed at the time of original construction is resulting in corrosion at the welds.
>
> The Fraser Gate IP pipeline portion of the these projects will replace a short 0.5 kilometre section of the existing Fraser Gate IP pipeline (1200 kPa NPS 30 IP) between Fraser Gate station in Vancouver and East Kent Avenue & Elliott Street with a 1200 kPa NPS 30 IP pipeline that meets FEI's seismic criteria for critical facilities to be resistant to a 1:2475-year event.

3.1 Is the field applied coating experiencing failures in other areas of the FEI pipeline system, or is this limited to this particular pipeline?

Response:

FEI is not aware of any other pipelines that have the same coating issues as the NPS 20 Coquitlam Gate IP pipeline. As corrosion is a time dependent failure mechanism, it is considered possible that other IP or DP pipelines may have similar coating issues, but have not experienced failures at this point in time. FEI has not detected this type of coating issue on the TP pipelines it has inspected using in-line inspection tools.

3.1.1 If limited to this particular pipeline, are there specific environmental or other factors which are contributing to the failures?

Response:

The corrosion on the NPS 20 Coquitlam Gate IP pipeline is primarily a result of the quality of installation of the coal tar enamel field applied joint coating during original construction.

Please also refer to the responses to BCUC IRs 1.1.1.7.1 and 1.1.1.7.2 for discussion of other factors considered during FEI's assessment of the pipeline.

3.1.2 If there are other factors contributing to the failures and consequent pin-hole leaks, are these expected to re-occur in the new pipeline?

Response:

The proposed new pipeline will be constructed with industry standard Fusion Bonded Epoxy (FBE) factory applied pipe coating and field applied liquid epoxy at girth weld locations. Modern day pipeline coatings, such as FBE or liquid epoxy, are subject to strict application procedures as well as a greater level of inspection and quality control. In addition, these coatings are designed to be compatible with cathodic protection in the case of coating disbondment, damage or degradation. This coating system is considered "non-shielding" in the case of failure or loss of adhesion and therefore cathodic protection will continue to protect the pipe from corrosion.

3.2 Are there any particular links between the Fraser Gate IP portion and the Coquitlam Gate IP pipeline portion such that the projects should be undertaken at the same time? Please explain.

Response:

The proposed Coquitlam Gate IP and Fraser Gate IP Projects both involve the construction and installation of NPS 30 pipe to replace existing pipe along sections of the two primary pipelines supplying gas to the Metro IP system. The Coquitlam IP Project as applied for is larger in scope; however, in general, both Projects share common attributes in terms of design, routing process, materials procurement and specialized construction and installation techniques due to their urban location. More specifically, with the replacement NPS 30 Coquitlam Gate IP pipeline in service, it will be possible to isolate the Fraser Gate IP pipeline and replace the seismically vulnerable segment of pipe with the proposed upgraded pipe without the use of a bypass. This particular link will require the commissioning window for both pipelines to be synchronized, and any delay in commissioning the Coquitlam IP pipeline would also likely delay the Fraser Gate IP pipeline commissioning.

It is therefore logical that both Projects should be undertaken at the same time in terms of planning, permitting, stakeholder consultation and ultimately construction and commissioning.

3.2.1 If there is no link between the two projects so that they need to be addressed simultaneously, could the Fraser Gate IP portion be deferred? Please explain why or why not.

Response:

Please refer to the response to CEC IR 1.3.2.

4.0 Reference: Exhibit B-1, Page 4

> The Lower Mainland is situated in a seismically active area. Seismic studies that have been conducted in recent years indicate that the section of the Fraser Gate IP pipeline between Fraser Gate station and the corner of East Kent Avenue & Elliott Street does not meet FEI's seismic criteria[5]. FEI's seismic criteria aligns with both the 2005 Building Code of Canada and FEI's understanding of the minimum criteria applied by other critical utility infrastructure operators in the Lower Mainland. At the present time, a full-bore rupture of the Fraser Gate IP pipeline due to a seismic event could result in significant public safety and economic consequences and would require the complete shutdown of the pipeline. The Fraser Gate IP pipeline is a major supply source of natural gas serving customers in Vancouver, Burnaby and the North Shore. In the event the Fraser Gate IP pipeline is shut down, up to 171,000
>
> [5] This criteria, which is documented in FEI's design standard DES-09-02 and included as Appendix A-28, is consistent with the design and construction of the two pipelines under the South Fraser River which was approved through BCUC order C-2-09 in 2009.

4.1 To which other 'critical utility infrastructure operators' in the Lower Mainland is FEI referring?

Response:

FEI is referring to electrical, communications, transportation, water, and sewer infrastructure operators in the Lower Mainland.

4.2 What size of seismic event would be needed to result in a full-bore rupture of the Fraser Gate IP pipeline?

Response:

A full bore rupture is estimated to occur for a seismic event with a mean return period of 800 years.

4.3 Are there other areas of the FEI pipeline that do not meet minimum seismic criteria either in the lower mainland or throughout the province?

Response:

Yes, there are other areas of the FEI pipeline that do not currently meet FEI's minimum seismic criteria documented in FEI's design standard DES 09-02 and included as Appendix A-28 (Exhibit B-1-1).

4.3.1 If yes, please identify which other sections in the Lower Mainland and in the remainder of the province do not meet the minimum seismic criteria.

Response:

Other sections of the FEI pipeline in the Lower Mainland and in the remainder of the province that do not meet FEI's minimum seismic criteria are listed in the table following.

FEI Site Reference #	Asset Name	Description of Site	Schedule for Mitigation
LM-1	Coquitlam	114mm IP to gravel pit north of Coquitlam and west of Coquitlam River	2017
LM-2	Maple Ridge – Port Coquitlam	323mm TP Pitt River crossing	2016
LM-4	Maple Ridge	168mm IP on north bank of Fraser River between Harrison St and 236th St	Not scheduled. Preliminary design underway.
LM-4	Maple Ridge	323mm TP on north bank of Fraser River between Harrison St and 236 St (Russell Reach Crossing)	Not scheduled. Preliminary design underway.
LM-5	Fort Langley	323mm TP across McMillan Island (Bedford Channel)	Not scheduled. Preliminary design underway.
LM-6	Richmond	219mm IP on south bank of north arm of the Fraser River, from River Rd Gate Station to Cambie Rd	2019
LM-10	Delta	168mm and 323mm TP pipelines to/from Tilbury Island LNG plant	2016
LM-12	Surrey	219mm and 323mm IP pipelines along 48 Ave and 152 St near Serpentine River	2020

4.3.1.1 Are the sections not meeting seismic criteria scheduled for upgrading?

Response:

No, not all of the sections that do not meet FEI's minimum seismic criteria have been scheduled for upgrading. In some cases, further assessment is underway either to confirm the risk to the integrity of the pipe or to develop a solution that will mitigate the concern in a cost effective manner. Please refer also to the response to CEC IR 1.4.3.1.

4.3.1.1.1 If so, when?

Response:

Please refer to the response to CEC IR 1.4.3.1.

5.0 Reference: Exhibit B-1, Page 6

> At the present time the existing Fraser Gate IP pipeline and Coquitlam Gate IP pipeline are not capable of providing security of supply to the customers normally served by each other under design day conditions. Due to lack of capacity on the Coquitlam Gate IP pipeline, these pipelines can be considered to be single point of failure pipeline segments. Failure of the NPS 30 pipeline at the Fraser Gate outlet would result in loss of service to up to 171,000 customers. Loss of the NPS 20 pipeline at the Coquitlam Gate outlet would result in loss of service to up to 41,000 customers. The economic impact to the general public, customers and the Company of a failure of the Fraser Gate IP pipeline or the Coquitlam Gate IP pipeline could be approximately $320 million or $64 million respectively. An increase in capacity of the Coquitlam Gate IP

5.1 If the Coquitlam Gate IP upgrade is complete, would the system be resilient enough to withstand a Fraser Gate IP failure?

Response:

Following completion of both proposed Projects, the Metro IP system would have the resilience to serve customers through possible anticipated future failure events, as well as to support isolation of segments for repair.

Please note that if the Fraser Gate IP pipeline is not replaced as proposed, a full-bore rupture of the pipeline resulting from a seismic event may result in a release of such gas volume that the capacity of the Coquitlam Gate IP pipeline would be exceeded, therefore resulting in system outages before the pipeline segment could be isolated.

6.0 Reference: Exhibit B-1, Page 8

> While each of the individual Projects noted above is a stand-alone project that is justified on its own merits in this CPCN, and can be constructed independently of the other Project, FEI has grouped the two Projects into this one CPCN due to the fact that they are related, complement one another and will provide regulatory and construction efficiencies if they are addressed at the same time.

6.1 Please confirm or otherwise explain that grouping the two projects into the single CPCN application can reasonably be expected to result in reduced regulatory expenses as compared to conducting them separately.

Response:

Confirmed.

6.2 Is the Commission required to approve the application in whole, or could the Commission approve one project and not the other? Please explain.

Response:

The Commission can approve one Project and not the other. Each of the individual Projects is a stand-alone project that is justified on its own merits, and can be constructed independently of the other Project. . However, as explained in the response to CEC IR 1.3.2, it is logical that both Projects should be undertaken at the same time in terms of planning, permitting, stakeholder consultation and ultimately construction and commissioning, and FEI has identified cost savings benefits that can be achieved by coordinating the construction of the Projects.

6.2.1 What, if any, issues would arise if the Commission were to approve either the Fraser Gate or the Coquitlam Gate project and not the other?

Response:

Together, the Projects will improve system integrity and safety, allow for full system resiliency and reduce the risk of gas supply disruption to up to approximately 171,000 customers residing in the Lower Mainland in the event of a failure. If only one of these Projects as applied for were approved, then FEI would not fully achieve these objectives and requirements.

Please also refer to the responses to BCUC IR 1.3.6 and CEC IR 1.65.1.3 for an outline of how joint approval of the Projects provides an opportunity for cost savings and improved constructability of the NPS 30 Fraser Gate IP seismic upgrade.

7.0 Reference: Exhibit B-1, Page 9

> - Total Capital Cost (As-spent dollars) excluding AFUDC but including abandonment and demolition cost is $250.216 million (including AFUDC the As spent cost is $263.664 million), and
> - 2019 Average Cost of Service Impact - $0.130 / GJ.
>
> For a typical FEI residential customer consuming 95 GJ per year in 2019, this would equate to approximately $12 per year and reflects an approximate increase of 3.39% on delivery margin or an approximate increase of 1.3% on the burner tip.[6]

7.1 What is the impact on average customers in each of the Commercial rate classes in 2019?

<u>Response:</u>

Based on approved commodity and common delivery rates effective January 1, 2015, the approximate annual bill impact for small commercial customers is forecast to be approximately 1.5% and for large commercial sales customers to be approximately 1.7%.

8.0 Reference: Exhibit B-1, Page 17

> The Coquitlam Gate IP pipeline has experienced a number of leaks since 1987. The failure mechanism, corrosion beneath disbonded field-applied coating at girth welds (further described below), is non-preventable. Due to current active corrosion on this pipeline, the leak frequency is expected to escalate over time.
>
> The pipeline is a steel pipeline, constructed of material and to the standards that were in place in 1958. The external coating of the pipe body (excluding girth weld regions) is a factory-applied coal tar enamel, and the construction girth welds are field coated with coal tar enamel. Despite appearing similar in name, the two coating systems (factory-applied and field coated) have performed dissimilarly over time. Long-term coating performance is primarily influenced by the application procedure (including ambient conditions at the time of application), which is recognized as being more controllable in a factory environment.

8.1 What was the expected service life of the pipeline when installed in 1958?

Response:

FEI has no knowledge of what the expected service life originally was when the NPS 20 Coquitlam IP pipeline was installed in 1958; however, in 1988 the depreciation rate applied was 2%, which would suggest an expected service life of approximately 50 years.

The experience of FEI and the pipeline industry suggests that many pipelines, through effective maintenance and integrity management programs, can be operated safely and reliably over a duration that exceeds 50 years.

8.2 What is the approximate normal range of service life for pipeline installed in the late 50's?

Response:

The experience of FEI and the pipeline industry suggests that many pipelines, through effective maintenance and integrity management programs, can be operated safely and reliably over durations that exceed their financial depreciation life. Please also refer to the response to CEC IR 1.8.1.

Neither FEI nor the pipeline industry has defined a normal range of service life for pipelines and as such the expected physical life for operations is evaluated for each asset individually. Based on analysis to date, no other complete IP or TP pipelines appear to require corrosion-related replacement within FEI long-term capital planning forecasts.

8.3 Are other pipelines installed in 1958 or thereabouts experiencing similar issues?

Response:

FEI, to date, has not experienced the same coating issues and subsequent leaks on other pipelines installed in the same era.

Please also refer to the response to CEC IR 1.3.1.

8.3.1 If not, please explain FEI's view as to why the corrosion is occurring on this pipeline and not on others.

Response:

The corrosion on the NPS 20 Coquitlam Gate IP pipeline is primarily a result of the quality of installation of the coal tar enamel field applied joint coating during original construction.

Specific installation practices from 1958 are unknown; however, it is believed that the joint coating issues experienced on the Coquitlam Gate IP pipeline are a result of some combination of surface preparation, environmental conditions during application, and the quality of the application (e.g. thickness).

As discussed in the response to CEC IR 1.3.1, FEI is not aware of any other pipelines with the same coating issues as the NPS 20 Coquitlam Gate IP pipeline. This could be due to differences in coating type, or the factors identified above.

8.3.2 If yes, please identify any other pipelines in the province in which FEI is experiencing similar issues.

Response:

Please refer to the responses to CEC IRs 1.3.1, 1.8.3 and 1.8.3.1.

8.4 Are the leaks occurring over the full length of the pipeline, or are they limited to certain segments of the pipeline?

Response:

Please refer to the response to BCUC IR 1.1.1.7.

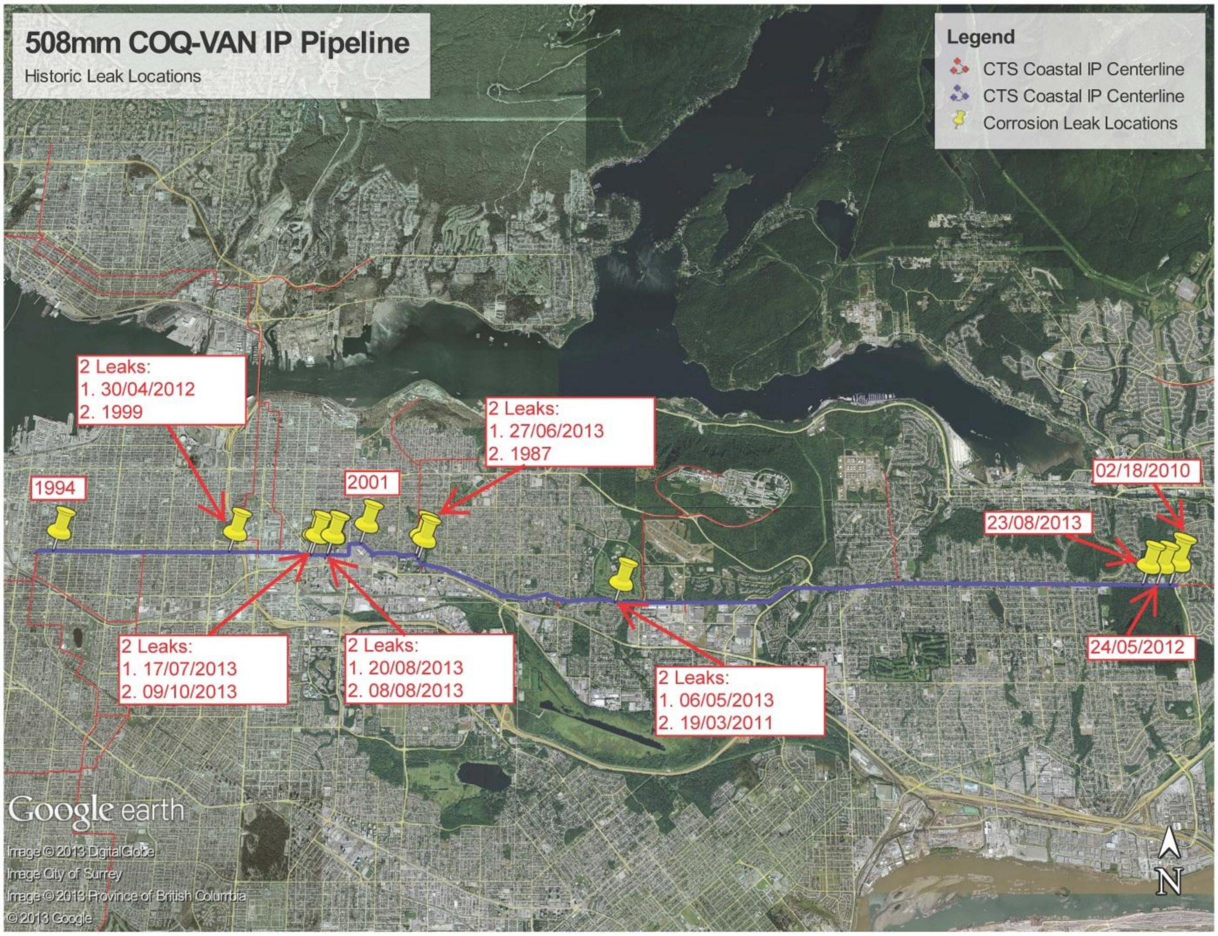
8.4.1 If the leaks are occurring only over certain segments of the pipeline, please identify which segments of the pipeline the leaks are occurring and why.

Response:

A map showing the location of all corrosion leaks on the NPS 20 Coquitlam Gate IP pipeline was included with FEI's Response to Oil and Gas Commission General Order 2013-25, appended as Appendix A-3 (Exhibit B-1-1). A reproduction of that map is shown below.

As discussed in the response to BCUC IR 1.1.1.5, similar local site conditions can result in similar corrosion rates which would explain the clustering of early leak occurrences. However, based on FEI's past excavations and leak history, corrosion is likely occurring at girth welds along the entire length of the existing Coquitlam Gate IP pipeline.

Please also refer to responses to BCUC IRs 1.1.1.7.1 and 1.1.1.7.2 for discussion of other factors considered during FEI's assessment of the pipeline.

1 
508mm COQ-VAN IP Pipeline
Historic Leak Locations
Legend
CTS Coastal IP Centerline
CTS Coastal IP Centerline
Corrosion Leak Locations
2 Leaks:
1. 30/04/2012
2. 1999
2 Leaks:
1. 27/06/2013
2. 1987
1994
2001
02/18/2010
23/08/2013
2 Leaks:
1. 17/07/2013
2. 09/10/2013
2 Leaks:
1. 20/08/2013
2. 08/08/2013
2 Leaks:
1. 06/05/2013
2. 19/03/2011
24/05/2012
Google earth
Image © 2013 DigitalGlobe
Image City of Surrey
Image © 2013 Province of British Columbia
© 2013 Google
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9.0 Reference: Exhibit B-1, Pages 19 and 20

> - Replacement meets the requirements of Canadian Standards association (CSA) Z662 Section 12.10.2.3 (d) which states "Where the condition of distribution or service lines, as indicated by leak records or visual observation, deteriorates to the point where they should not be retained in service, they shall be replaced, reconditioned, or abandoned". Replacement also meets the requirements of the BC Oil and Gas Activities Act Section 37 (3) which states "A person who is aware that spillage is occurring or likely to occur must make reasonable efforts to prevent or assist in containing or preventing the spillage".
>
> The OGC replied to FEI on December 18, 2013 that they had received and reviewed FEI's response to order 2013-25.

9.1 Please confirm or otherwise explain that the pipeline still has not yet deteriorated to the point that it cannot be retained in service.

Response:

As discussed further in the response to BCUC IR 1.2.2, FEI has assessed that the existing NPS 20 Coquitlam Gate IP pipeline is nearing the end of its useful life and requires replacement.

However, consistent with FEI's response to Oil and Gas Commission (OGC) General Order 2013-25, included as Appendix A-3 (Exhibit B-1-1), FEI has assessed that the existing NPS 20 Coquitlam Gate IP pipeline is suitable for continued service with the present interim mitigation activities, primarily the increased leak survey frequency, until the pipeline can be replaced. Additionally, FEI has outlined a replacement plan to the OGC.

9.2 Please confirm that with continued mitigation measures the pipeline will not necessarily deteriorate to the point that it cannot be retained in service.

Response:

Please refer to the response to BCUC IR 1.2.2 for FEI's assessment that the existing NPS 20 Coquitlam Gate IP pipeline is nearing the end of its useful life and requires replacement. FEI has not identified any mitigation activities, other than replacement of the pipeline, which will prevent future leaks. Interim mitigation activities were established to ensure the suitability of the pipeline for continued service until pipeline replacement.

FEI does not consider ongoing operation of the pipeline, in the absence of a replacement plan, to be an appropriate operating strategy.

9.3 Please provide a copy of the OGC reply to FEI on December 18, 2013.

Response:

Please refer to Attachment 9.3.

10.0 Reference: Exhibit B-1, Page 20

3.1.2.3 An Operational Flexibility and System Resiliency Opportunity

FEI recognizes the existing Coquitlam Gate IP pipeline requires replacement in order to mitigate future gas leaks resulting from non-preventable active corrosion. In addition to the integrity related risk associated with the Coquitlam Gate IP pipeline, FEI also identified other capacity related constraints on the Metro IP system that warrant consideration in the selection of a prudent replacement solution:

1. Operational Flexibility: Over time and with growth in demand on the system there has been an erosion of the operational flexibility required to facilitate planned work on the Fraser Gate IP pipeline; and
2. System Resilience: The Fraser Gate IP pipeline and the Coquitlam Gate IP pipeline are identified as single point of failure pipelines at the present time, if either pipeline fails, there is no alternate supply capacity sufficient to provide year round system resiliency to mitigate potential consequences that could occur as a result of unplanned outages.

10.1 Please confirm or otherwise explain that the driving impetus to replace the pipeline is the requirement to mitigate future gas leaks, and that it is primarily a circumstantial advantage that the proposed replacement solution is also able to address resiliency capacity related constraints on the Metro IP system.

Response:

Confirmed. FEI believes that it has a unique, one-time opportunity to address the system resiliency and operating flexibility of the Metro IP distribution system that otherwise would be more difficult to justify. The result will be a safer and more reliable gas delivery system. Please refer to the response to BCUC IR 1.4.1.2 for further discussion on the justification for addressing constraints to resiliency now through the Coquitlam Gate IP Project.

10.1.1 If confirmed, would FEI replace the pipeline if there was no additional benefit to be derived from eliminating the capacity related constraints, or would FEI adopt another alternative? Please explain

Response:

As discussed further in the response to BCUC IR 1.2.2, FEI has assessed that the existing NPS 20 Coquitlam Gate IP pipeline is nearing the end of its useful life and requires replacement. As such, FEI would pursue replacement regardless of the presence of any capacity-related system constraints. The Company considered Project alternatives that would address only the condition-related concerns of the pipeline, however these solutions were rejected as they did not meet the objectives of providing operational flexibility and system resiliency.

Please also refer to the response to CEC IR 1.10.1.

10.2 If not confirmed, is the driving impetus the requirement to address the resiliency capacity related constraint?

Response:

Please refer to the responses to CEC IRs 1.10.1 and 1.10.1.1.

10.3 Please confirm that the OCG does not require the pipeline to be replaced nor decommissioned, nor has it otherwise declared the pipeline to be unsafe at this time.

Response:

As discussed further in the response to BCUC IR 1.2.2, FEI has assessed that the existing NPS 20 Coquitlam Gate IP pipeline is nearing the end of its useful life and requires replacement.

Given that FEI has not identified any mitigation activities, other than replacement of the pipeline, which will prevent future leaks, FEI believes that replacement is congruent with the requirements of the Oil and Gas Activities Act and the Canadian Standards Association Z662 standard (refer to the response to BCOAPO IR 1.1.1). On that basis, FEI has developed a plan to address the ongoing, non-preventable, active corrosion by replacing the pipeline and has notified the OGC of that intended course of action.

The OCG has not required the pipeline to be replaced or decommissioned, or otherwise declared the pipeline to be unsafe at this time. However, the OGC is fully aware of FEI's assessment that replacement of the existing NPS 20 Coquitlam Gate IP pipeline is the most appropriate mitigation method.

11.0 Reference: Exhibit B-1-1, Appendix A-1, Page 4

> In order to determine the consequences associated with an unintended release of gas from the pipeline, two potential modes of failure were considered – leak and rupture. A 'leak' is defined as a loss-of-containment arising from a through-wall penetration of a corrosion defect, with the extent of the penetration being confined to the area of through-wall corrosion, and with no extension of the opening through instability at the edges of the flaw. A rupture is defined as a loss-of-containment that results from instability of the wall loss area, leading to the formation of fracture faces and a full-bore opening.
>
> The analysis showed that the probability of rupture was below the resolution of the reliability method (10^{-07}) for the twenty-year evaluation period 2013 – 2033. This is attributed to the low operating stress level of the pipeline, relative to the defect size distribution, which results in a lack of predicted structural instability through all possible combinations of defect geometry and growth period.

11.1 Why did the analysis assume a twenty year evaluation period?

Response:

DRAS provides the following response:

The purpose of the analysis provided in Appendix A-1 was to complete a quantitative reliability assessment of the NPS 20 IP Coquitlam pipeline, and to provide insight as to how the reliability of that pipeline will change over time. A 20-year period was selected as the basis of that analysis, since it represented a reasonable time period over which those objectives could be met while maintaining confidence in the predictions made. Predictions made over longer periods would be subject to lower levels of confidence due to uncertainties associated with the potential for the initiation and growth of new corrosion defects, and uncertainties regarding corrosion growth rates over time.

11.2 Would the probability of a rupture increase with a longer evaluation period? Please explain.

Response:

No. Due to the low operating stress levels in the existing NPS 20 Coquitlam Gate IP pipeline, no corrosion defects are projected to grow to the length required for rupture prior to penetrating the pipe wall thickness and leaking. As a result, all future corrosion failures are expected to result in leaks and not rupture.

12.0 Reference: Exhibit B-1-1, Appendix A-1, Page 5

Table 1
Leak and Rupture Frequencies Vs. Time

Year	Frequency of Rupture	Frequency of Leak
2013*	0	8.7
2018	0	12.8
2023	0	17.9
2028	0	23.8
2033	0	31.9

* 2013 results are provided only for purposes of a comparison against actual incident rates (note that seven leaks and zero ruptures occurred in 2013).

As can be seen from the above Table, based on the dataset used, the predicted number of leaks in the year 2013 is slightly higher, but very close to the value that was actually experienced. This helps confirm the predictive nature of the reliability method used.

For natural gas transmission pipelines, the consequences that are associated with ruptures are much more significant than the consequences associated with leaks. In that respect, because the analysis illustrates that ruptures are not likely to occur through the next 20 years of operation, risk is associated only with leak scenarios through that operating period. It should be borne in mind, however, that with respect to leaks, the potential for adverse consequences increases with leak magnitude. This is particularly true in urban environments, where leaks can potentially migrate into adjacent buildings via subterranean pathways. The release rate associated with a leak is proportional to both the area of the hole and operating pressure. For instance, the leak rate will double with a doubling of hole area; similarly, it will double with a doubling of operating pressure. Due to a lack of data, it was not possible to comment on the range of potential hole sizes or leak magnitudes, and so it is feasible that despite the negligible risk associated with ruptures, there may be a significant operating risk associated with leaks. This is particularly true for large hole sizes and higher operating pressures. For the particular pipeline that was the focus of this study, the operating risk associated with leaks is expected to increase by a factor of 3.7 over the period 2013 – 2033.

12.1 Please explain what types of data to define hole size and leak magnitude would be required that was not available.

Response:

DRAS provided the following response:

The context of the section from Appendix A-1 that was cited in this information request pertains to the potential for subterranean leaks to present a hazard to adjacent buildings. Under certain circumstances involving natural gas leaks in heavily-developed urban environments, natural gas can seep into adjacent buildings where it can present a public safety hazard. Factors affecting the potential for such scenarios to occur include:

- Leak rate
- Soil permeability
- Existence of low-permeability ground cover
- Proximity of buildings to the leak
- Type and configuration of subterranean infrastructure that can form a migration pathway from the site of the leak to the foundation of adjacent buildings
- Building ventilation

13.0 Reference: Exhibit B-1-1 Appendix A-3, Page 5

> Consequence reduction measures are relevant to the subject pipeline's operation, due to the assessed lack of effective methods to prevent future leaks. Due to the pipeline operating at low stress levels (17% SMYS) it is expected to fail by leak, not rupture. The corrosion failure mechanism will result in pinhole penetrations that would grow only if left unrepaired.

13.1 IS FEI able to repair pinhole penetrations in a sufficiently timely manner to prevent growth? Please explain why or why not.

Response:

Confirmed. The frequency of FEI's leak survey program for the existing NPS 20 Coquitlam Gate IP pipeline ensures that corrosion leaks are detected shortly after developing and before significant leak hole diameter growth can occur. This allows repairs to be completed in a timely manner.

14.0 Reference: Exhibit B-1-1, Appendix A-3, Page 1

Attn: Dean Zimmer
Director, Compliance and Enforcement
BC Oil and Gas Commission

Re: General Order 2013-25

FortisBC is submitting the attached documentation in response to Order 2013-25, pertaining to BC Oil and Gas Commission ("Commission") Pipeline Project 1045. FortisBC has assessed that the 508 mm pipeline installed in 1958 as Pipeline Project 1045 ("subject pipeline") is suitable for continued service, and is being operated in accordance with the requirements of CSA Z662-11.

Through implementation of an Integrity Management Program, FortisBC manages and/or mitigates hazards on our system that have the potential to result in failure with significant consequences. This has resulted in incremental mitigation activities, including increased leak survey frequency. In addition, FortisBC has outlined a replacement plan for the subject pipeline that is currently planned for submission to the BC Utilities Commission in 2014. This plan addresses FortisBC's requirement as a Permit Holder under Section 37 (1) (a) of the BC Oil and Gas Activities Act to "prevent spillage".

We would appreciate the opportunity to meet with representatives of the Commission to review and discuss the content of our submission. I can be reached at 604-592-7701 (office) or 604-908-3060 (cellular) to discuss a suitable time and location.

Sincerely,

Nov. 27, 2013

Bryan Balmer, P.Eng.
Manager, System Integrity Programs
FortisBC

14.1 When did FEI determine that replacement of the pipeline was necessary?

Response:

As a result of information obtained during excavations (2011-2013) and the leak history, FEI was actively studying options for long-term management of the NPS 20 Coquitlam Gate IP pipeline by Q1 2013. A decision by the Company to pursue a CPCN for pipe replacement was reached in Q3 2013.

14.2 What was the basis for determining that replacement was necessary?

Response:

As discussed in the response to BCUC IR 1.2.2 and FEI's Response to Oil and Gas Commission General Order 2013-25, included as Appendix A-3 (Exhibit B-1-1), the existing NPS 20 Coquitlam Gate IP pipeline was assessed as nearing the end of its useful life due to the non-preventable and increasing projected leak frequency resulting from external corrosion beneath the field-applied girth weld coating along the length of the pipeline.

As also discussed in the above references, FEI has not identified any mitigation activities, other than replacement of the pipeline, which will prevent further leaks.

Given the above, FEI does not consider ongoing operation of the pipeline, in the absence of a replacement plan, to be an appropriate operating strategy. Also, FEI believes that replacement is congruent with the requirements of the Oil and Gas Activities Act and the Canadian Standards Association Z662 standard. Please also refer to the response to BCOAPO IR 1.1.1.

15.0 Reference: Exhibit B-1-1, Appendix A-3, Page 5

> FortisBC's standard leak survey frequency for pipelines in Class 3 locations operating at pressures above 700 kPa is annual. To locate leaks at the pinhole stage, FortisBC has implemented increased leak survey frequency for the subject pipeline. A further degree of feature growth and/or of gas migration may be necessary prior to leaks becoming detectable by the public (through odorant present in the gas) versus targeted leak surveys.
>
> Therefore, primarily in response to observed leak frequencies, FortisBC increased leak survey frequency of the subject pipeline to quarterly on March 4th, 2013. This frequency was further increased to weekly on August 22nd, 2013. To facilitate leak survey, vegetation control frequencies have also been increased over some segments. This enables ready access to the pipeline for surveys, and also to complete any subsequent repairs.

> Leak management and response is another important element of FortisBC's operations. To support optimal leak response for the subject pipeline, FortisBC has implemented the following measures:
>
> - Pretested pipe and stopple equipment have been acquired to facilitate leak repair during cold weather conditions if a bypass is needed to maintain service to customers.
> - Bypass sizing requirements have been assessed to expedite repair planning.
> - Repair sleeves have been manufactured and are being stored for use on the subject pipeline.

15.1 Please quantify the additional costs that were expended in 2013 as a result of the increased leak survey frequency, increased vegetation control, increased condition assessment and any other costs incurred mitigating the potential effects of the leaks.

Response:

Please refer to the response to BCUC IR 1.1.1.9.

15.1.1 Please confirm that these costs would continue for the foreseeable future in the event that the project was not undertaken.

Response:

Confirmed.

Please also refer to the response to BCUC IR 1.7.1.

15.1.2 Please confirm or otherwise explain that these incremental costs will be eliminated once the new pipeline is in place.

Response:

Confirmed. Any incremental costs associated with the current leak response measures for the subject pipeline will be eliminated once the new pipeline is in place.

16.0 Reference: Exhibit B-1-1, Appendix A-3, Page 6

> With the operating practices identified above, FortisBC does not anticipate the subject pipeline becoming inoperable. Safety risk is being managed through odorization, leak detection, and leak response.
>
> Environmental impact is also being managed through early leak detection and response. In addition, FortisBC has analyzed gas volume estimates at past leaks and concluded that the incremental environmental risk due to leaks on the subject pipeline is not material. Leaks that have occurred in 2013 on the subject pipeline comprise less than 0.1% of the FortisBC Energy Inc. yearly GHG emissions.
>
> FortisBC has recognized the potential for increasing resource pressures in our Operations group if the leak frequency increases significantly prior to replacement. Potential mitigation strategies to address this are under development.

16.1 Please provide further details with quantification of the potential for increasing resource pressures in the Operations group if the leak frequency increases significantly.

Response:

Repairing major leaks on an unscheduled basis requires internal resources otherwise scheduled for planned O&M and capital activities. To the extent that these types of scheduled activities can be reassigned to contractors (e.g. new mains and services work), there is minimal impact to internal Operations resources albeit promised customer install dates may be at risk.

Where contract labour cannot be substituted for internal resources to complete planned O&M activities, increased leak repair frequencies may result in rescheduling or deferring of other O&M work or possibly an increase in overtime for internal resources to meet planned dates.

Please also refer to the response to BCUC IR 1.7.1 for a forecast of O&M expenses for Alternative 1 (Status Quo), demonstrating the financial impact for the projected leak frequency increase.

16.2 Please describe the additional potential mitigation strategies that FEI developed, along with the expected costs for each strategy.

Response:

FEI has preliminarily considered increasing operations resources to meet leak response pressures, however has not fully developed this strategy and no associated cost estimate has been prepared. Subsequent to the assessment, FEI determined that, given the timing and extent of the leak repairs likely to occur prior to pipeline replacement (per the Dynamic Risk study included as Appendix A-1 (Exhibit B-1-1)), management of leaks by internal resources was likely feasible by rescheduling or deferring other planned work.

17.0 Reference: Exhibit B-1-1 Appendix A-3, Page 6

> Specific to the subject pipeline, we will continue to monitor the following measures within our Integrity Management Program Dashboard:
>
> - completion of leak surveys in accordance with plan
> - odorization management
>   - sampling program completion
>   - odor sample results within tolerances
>   - odorizer adjustment and re-sampling completion, when required
>   - odorizer level measure and fill completion
>   - completion of injection odorizer maintenance

17.1 Please provide the incremental costs that would accrue annually from monitoring activities if the pipeline were not replaced.

<u>Response:</u>

FEI would be required to continue with incremental leak survey costs at approximately the 2014 expenditure levels, as included in the response to BCUC IR 1.1.1.9.

18.0 Reference: Exhibit B-1-1 Appendix A-3, Page 8

> The data acquired from the excavation / assessments are representative for the most part of regions in the vicinity of field girth welds, where the bulk of the coating failure had been observed. It should be noted however, that where over-the-ditch coating systems might be used, there is no reason to suspect that the girth weld area would be any more or less susceptible to coating failure than the rest of each joint of pipe. For the purposes of the reliability analysis, data from all excavations (with the exception of data from four features, which were considered to be statistical outliers) were used in developing the size distribution functions. For the development of corrosion feature incident rates, however, data from the leak site excavations were excluded so as to remove potential sampling bias.

18.1 Please confirm or otherwise explain that over-the-ditch coating systems was generally undertaken only at the weld sites, and elsewhere the coating was factory applied.

Response:

Based on observations from leak repairs and integrity excavations, and awareness of typical construction practices appropriate for the period, FEI expects that the majority of the pipeline coating was factory applied. In addition to weld sites, other locations where over-the-ditch coatings would have been used include fittings, sharper field bends and where coating damage was observed and repaired during original construction.

19.0 Reference: Exhibit B-1-1, Appendix A-3, Page 9

Table 3: Excavation Data (2011 to current)

Year	Dig Location	Summary of Findings	Mitigation	Number of Girth Welds Exposed	Approximate Length of Pipe Exposed (m)
2011	Lane behind Brentlawn west of Fairlawn	Corrosion under disbonded field applied coating at girth weld – 70% through Wall. Shop applied coating in excellent condition.	Weld Sleeve installed and recoat	2	14
2011	Lane behind Brentlawn west of Fairlawn	Corrosion under disbonded field applied repair coating from 2001 Leak (Polymer Tape). Shop applied coating in excellent condition.	Recoat	1	4
2011	Lane behind Brentlawn west of Fairlawn	No corrosion found under field applied coating. Filed applied and shop applied coating in excellent condition.	Recoat	1	2.86
2011	West of 7504 Broadway Avenue	Corrosion under disbonded field applied coating at girth weld – 49% through Wall. Shop applied coating in excellent condition.	Recoat	1	3.9
2011	West of 7504 Broadway Avenue	No corrosion found under field applied coating. Filed applied and shop applied coating in excellent condition. Minor disbondment noted.	Recoat	1	3.66
2011	West of 7504 Broadway Avenue	No corrosion found under field applied coating. Filed applied and shop applied coating in excellent condition. Minor disbondment noted.	Recoat	1	3.61
2012	Como Lake Avenue west of Mariner	No corrosion found under field applied repair coating (Polymer Tape). Shop applied coating in excellent condition.	Recoat	1	4.8
2012	Como Lake Avenue west of Mariner	No corrosion found under field applied coating. Shop and field applied coating in excellent condition. 4 coating holidays found in shop applied coating which corresponded to 4 active corrosion features (max depth 46%)	Recoat	1	11.4

19.1 How much of the total pipeline has been recoated to date?

Response:

Approximately 140 metres of pipe, including 38 girth welds, has been recoated during integrity dig inspections and leak repairs. The represents less than 1% of the total pipeline length and approximately 2% of the total expected number of girth welds.

19.2 Please confirm that FEI considers the recoat to be fully effective in treating the corrosion.

Response:

Confirmed.

Proper recoating, including the use of proven non-shielding type coatings compatible with cathodic protection, will arrest active corrosion and prevent future corrosion from occurring by insulating the steel pipe surface from the soil.

In the event of the new coating deteriorating, becoming damaged, or disbonding over time, it is designed to allow cathodic protection to be effective in reducing corrosion rates to negligible levels.

19.2.1 If not, please explain why not and identify what other activities would need to be completed in order for the corrosion to be adequately addressed.

Response:

Please refer to the response to CEC IR 1.19.2.

19.2.2 What is the cost of a girth weld recoating on a per girth weld basis?

Response:

An estimate to rehabilitate the existing NPS 20 Coquitlam Gate IP pipeline was included in Section 3.2.2.2 (Page 33) of the Application. This estimate utilized an average cost of $92,200 per girth weld, based on average actual dig and repair costs from 2011-2013.

20.0 Reference: Exhibit B-1, Page 17

> FEI evaluated several above ground techniques used to locate areas of ineffective coating and determined that they were ineffective at locating the coating disbondment that was leading to corrosion damage. As such, FEI is unable to determine where coating failure has occurred and where corrosion which may lead to failure is likely to exist.

20.1 Please give a list of the types of above ground techniques evaluated for locating the coating disbondment.

Response:

FEI evaluated the following above ground techniques in an attempt to locate coating disbondment. The results of these surveys were validated by direct inspection (digs).

Close Interval Potential Survey (CIPS) – this survey method primarily evaluates the level of cathodic protection applied to a pipeline. Dips or valleys in a CIPS profile are indicative of coating damage where steel is exposed to soil. This survey was unable to locate locations where the field-applied girth weld coating had disbonded.

AC Current Attenuation (ACCA) – also known as Current Mapping, this survey method provides a general indication of coating condition as well as locating electrical shorts on the cathodic protection system. Locations of coating damage are identified by sudden losses of the induced low frequency AC current signal. This survey was unable to locate locations where the field-applied girth weld coating had disbonded.

AC Voltage Gradient (ACVG) – this survey method can pinpoint locations of coating damage with greater accuracy than ACCA (+/- 1m). This survey method measures the AC voltage gradient produced in the ground surrounding a coating holiday[1], where the induced low frequency AC signal discharges from the pipe. ACVG has been demonstrated to be very successful in locating true coating damage (where steel is exposed to soil), however where the coating is disbonded but intact, current is not discharged from the pipe and therefore no voltage gradient is produced. This survey was unable to locate locations where the field-applied girth weld coating had disbonded.

DC Voltage Gradient (DCVG) – similar to ACVG, this survey method can pinpoint locations of coating damage with greater accuracy than ACCA (+/- 1m). The DCVG technique can also determine the relative size and location on the pipe of the coating holiday. DCVG utilized the DC Cathodic Protection current as opposed to ACVG where a low frequency AC signal is induced

[1] Coating holiday refers to an undesirable discontinuity in the pipeline coating which exposes the underlying steel to the surrounding environment and which could therefore be site for corrosion development.

onto the pipeline. This survey method measures the DC voltage gradient produced in the ground surrounding a coating holiday, where the DC cathodic protection current is picked up by the pipe. As with ACVG, DCVG has been demonstrated to be very successful in locating true coating damage (where steel is exposed to soil). However, where the coating is disbonded yet intact, DC current is not picked up by the pipe and therefore no voltage gradient is produced. This survey was unable to locate locations where the field-applied girth weld coating had disbonded.

21.0 Reference: Exhibit B-1, Page 20

> 3.1.2.3.1 LIMITED CAPACITY TO PROVIDE OPERATIONAL FLEXIBILITY
>
> For a significant part of the service life of the Metro IP system, there has been sufficient capacity to provide operational flexibility in the system such that during warmer periods, the system could be supported for some period without the primary supply from Fraser Gate station. This allowed FEI an operational window to interrupt the supply from Fraser Gate station to facilitate planned work on the Fraser Gate IP pipeline that requires isolation of the flow. Over time and with growth in demand on the system, this operational flexibility has been eroded such that currently the existing NPS 20 Coquitlam Gate IP pipeline cannot be relied on to support the Metro IP System at any time of year without some support from Fraser Gate station, through the Fraser Gate IP pipeline.
>
> Operational flexibility is the ability to isolate a section of pipeline as required for planned or scheduled maintenance without impacting supply to customers. Operational flexibility can be improved by adding pipeline loops or providing multiple sources of supply within a system.

21.1 Do most FEI systems in major centres have sufficient capacity and the operational flexibility to allow for planned work and isolation of the flow without bypass?

Response:

The level of operational flexibility available varies in major centers throughout the FEI service territory. Most FEI systems in major centers outside of Metro Vancouver are much smaller in scale than the Metro IP system with proportionally smaller pipe diameter and numbers of customers served. In general, these systems have varying degrees of ability to allow for planned work through isolating a pipeline segment without need of a bypass. However, due to the smaller size of the pipelines, installation of bypass piping may be less costly, complicated, and time consuming to implement than is the case for the Fraser Gate or Coquitlam Gate IP pipelines.

21.1.1 If no, why is this operational flexibility necessary in the Metro IP system and not elsewhere?

Response:

The proposed Projects do not imply that operational flexibility is not important elsewhere; rather that a unique, one-time opportunity exists to address this issue within the Metro IP system in conjunction with a necessary pipeline replacement.

Please refer also to the response to BCUC IR 1.4.1.2 for a discussion regarding the justification for operational flexibility in the Metro IP system.

21.2 For how long has the operational flexibility been eroded such that the existing NPS 20 Coquitlam Gate IP pipeline cannot ever be relied upon to support the Meter IP system without the primary supply from Fraser Gate station?

Response:

Please refer to the response to BCUC IR 1.3.3.1.

21.2.1 Please describe with quantification any negative consequences that have arisen from this situation.

Response:

Since 2002, FEI has not encountered any situation requiring the isolation of the IP pipeline segments most impacted by the lack of resiliency and operational flexibility (the pipeline segments upstream or just downstream of Fraser Gate). However, although FEI has effective practices in place for damage prevention, third party damage to the pipelines is always a possibility. Should planned or urgent work be required or if the pipeline is damaged by third party activity, please refer to the response to CEC IR 1.22.1.2 for an example of estimated bypass piping costs. Additionally, as described in Exhibit B-1, several leaks have occurred in segments of the existing NPS 20 IP Coquitlam Gate pipeline. To date, the leaks on this pipeline have occurred at times when the prevailing weather and the location on the pipeline have allowed isolation to mitigate adverse consequences and allow repair. Faced with the increasing rate of leak occurrence in 2013 and in anticipation of more leaks occurring at locations that would not allow isolation without bypass piping, FEI has assembled an inventory of material sufficient to install the bypass required on the NPS 20 Coquitlam Gate IP pipeline, should a leak occur in peak winter conditions.

Achieving full resiliency, as discussed in the response to BCUC IR 1.4.1.2, will be effective in avoiding negative consequences associated with delays and costs for preparing and installing bypasses or from customer outages if isolation must occur before bypasses can be installed.

21.3 Please provide all studies completed of the operational resiliency or flexibility requirements.

Response:

Please refer to Confidential Attachment 21.3 for the redacted study of the resiliency of the alternatives considered as part of the Lower Mainland System Upgrade Projects. The information is filed confidentially as it contains detailed asset security and system operation information, the disclosure of which can impact the security of FEI assets. In addition, FEI has redacted certain sections and tables where the redacted information does not pertain to either the Coquitlam Gate IP or the Fraser Gate IP Projects.

22.0 Reference: Exhibit B-1, Page 22

> Both the Coquitlam Gate IP and Fraser Gate IP pipelines are large diameter pipelines which have long segments located within busy roadways. Stopple and bypass operations are major undertakings from a financial and time/effort perspective and require significant planning and engineering. Excavations on these large pipelines, required for stopple/bypass operations, are significant as the pipe is often buried at depths exceeding 2 metres. Other infrastructure in the roadway such as water, sewer, power, cable, and telephone can complicate installation of stopple fittings, bypass piping, and installation of shoring cages to make excavations safe. Routing of bypass piping is often difficult in these confined urban areas. Fittings welded to pipelines result in a loss of depth of cover and may require extension of bypass lengths to ensure minimum depth of cover is achieved. Interruptions due to excavations and bypass routing can have major and extended impacts on traffic and local access.

> Maintenance work is typically scheduled to minimize the need for bypasses. The period of time where isolation can be achieved without installation of bypasses is typically called the maintenance window. This period of time varies for most segments depending on the time of year (system load). At some time in the future, FEI expects there to be maintenance required on the Fraser Gate IP pipeline, including pipe segment replacement due to integrity issues such as corrosion or river crossing erosion, seismic upgrades, and valve/fitting replacements. It should be expected that over the operating life of the pipeline that sections of pipelines will require renewal due to mechanisms such as corrosion. Pipeline modifications are often required to meet outside requests such as pipe lowering or relocations for road work. Scheduling these maintenance activities can be difficult depending on the urgency of the request and the time of year. Delays to these maintenance projects may occur as a result of a lack of operational flexibility.

22.1.1 How long of an operational window does FEI possibly need for the anticipated work on the Fraser Gate IP pipeline?

Response:

Anticipated work, as stated in the question, intimates that it is foreseen and therefore can be planned, as opposed to unplanned work which is typically in the form of emergency response (e.g. a leak or third party line hit). Planned work on the Fraser Gate IP pipeline could involve a range of pipeline maintenance or upgrade activities from a relatively benign inspection dig to the replacement of pipe, valve or fitting, pipe lowering or other pipeline modifications. The window of time required to complete this work would largely depend on if normal gas flow through the pipeline would be disrupted by the work. If so, the time of year and location would dictate the bypass configuration required to maintain gas supply to downstream customers. The installation of a bypass prior to completion of the planned work, and then removal again afterwards requires additional time that would add significantly to the overall completion timeline. Therefore, based on these examples of anticipated work, the operational window to implement the onsite construction could range from less than a week to well in excess of a month if a bypass is required. Effectively, a bypass can be used to create an operational window of any length of time for planned maintenance and repair. If unanticipated or unplanned repair is required on the Fraser Gate IP pipeline on an emergency basis, then a bypass would most certainly be required as flow through the pipe would need to be isolated to make these repairs. The nearer to Fraser Gate station on the pipeline and the further into the cooler fall and winter season, the larger and more time consuming and complex the bypass would be to install. As an emergency situation may require isolation of the gas supply quickly to ensure public safety, sufficient time to install a bypass may not be available and significant customer outages would result.

22.1.2 Please provide anticipated costs, on an order of magnitude basis, for undertaking bypass for the maintenance required on the Fraser Gate IP pipeline.

Response:

An indicative cost estimate for installing a bypass for maintenance required on the NPS 30 Fraser Gate IP pipeline is approximately $0.8 million. Please refer to the response to BCOAPO IR 1.3.7 for additional detail regarding bypass costs. Longer and/or larger diameter bypasses would increase this cost.

22.1.3 Please confirm or otherwise explain that the proposed replacement project would result in savings from bypass in the order of magnitude identified in Question 23.1.3 above.

Response:

The proposed Fraser Gate IP Project will be constructed at the same time as the Coquitlam Gate IP Project. However, the Coquitlam Gate IP pipeline will be commissioned prior to the final tie-in procedure to connect the Fraser Gate replacement pipe to the network; therefore, a bypass will not be required at Fraser Gate and, as such, the associated cost of a bypass is not included in the cost estimate.

23.0 Reference: Exhibit B-1, Page 22

> In the past all segments on the Coquitlam IP and Fraser Gate IP had maintenance windows where work could be carried out without the need for bypass. Over time, due to load growth, this maintenance flexibility has been eroded such that the pipeline segments immediately
>
> downstream of the Fraser Gate station require bypass piping to be installed at all times of the year, and pipeline segments downstream of Coquitlam Gate will require bypass piping to be installed in winter conditions. Over time, the operational flexibility will continue to erode, making routine maintenance more complicated and costly to perform, with increasing impact on the public.

23.1 Has FEI been required to undertake bypass in the past for maintenance work in the affected areas by this application (downstream of the Fraser Gate station and Coquitlam Gate) that would otherwise have been managed with the maintenance window?

Response:

No. Please also refer to the response to CEC IR 1.21.2.1.

23.2 If yes, please identify how many times this has occurred and provide an approximate cost of the bypass that was required.

Response:

Please refer to the response to CEC IR 1.23.1.

23.3 If not, please explain why not.

Response:

No maintenance work requiring isolation of the Fraser Gate IP pipeline has been undertaken in the period since 2003 when an outage window was no longer available on the pipeline.

24.0 Reference: Exhibit B-1, Page 22

> The replacement of the existing Coquitlam Gate IP pipeline with an enhanced capacity pipeline will provide FEI the ability to create an extended operational window to facilitate planned maintenance.

24.1 For how long will the operational window be extended?

Response:

With the proposed Coquitlam Gate IP NPS 30 pipeline operating at 2070 kPa the operational window will extend year round.

25.0 Reference: Exhibit B-1, Page 24

> As a result, the Fraser Gate IP pipeline and the Coquitlam Gate IP pipeline are identified as single point of failure pipelines because if either pipeline fails, there is no alternate supply to serve all of the customers currently served by the other pipeline segment.

25.1 How many other ‘single point failures’ are on FEI’s Metro pipeline?

Response:

The determination of all the “single point failures” on FEI’s Metro IP pipeline system would require a significant amount of analysis considering various scenarios and events; thus, this analysis has not been undertaken. However, there are approximately six obvious system pipe configurations, namely the IP laterals branching from the existing Fraser Gate and Coquitlam Gate IP pipelines, that represent single points of failure whereby if the pipeline failed, there is no alternate supply to serve all the customers currently served by the pipeline. However, as discussed in response to CEC IR 1.21.1, due to their smaller size, installation of bypass piping is significantly less costly, complicated, and time consuming to implement than is the case for the Fraser Gate or Coquitlam Gate IP pipelines. Thus the risk presented by these single points of failure is not of the same magnitude as the Fraser Gate or Coquitlam Gate IP pipelines.

25.1.1 If there are other single point failures on the Metro IP system, when are they scheduled for upgrading?

Response:

As the other locations of potential single point failures on the Metro IP system have significantly lower consequences than the Fraser Gate IP pipeline and the Coquitlam Gate pipeline, they are currently not scheduled for upgrading.

Please also refer to the response to BCUC IR 1.5.1.5.1.

26.0 Reference: Exhibit B-1, Pages 31 and 32

3.2.2.1 Alternative 1 - Do Nothing (Status Quo of Continuing Ongoing Integrity and Leak Management)

This alternative would require ongoing regular integrity management activities and increased leak inspections.

This alternative will not address the reliability, safety, or regulatory concerns associated with the unacceptable projected frequency of gas leaks and may eventually put FEI in a position where it is no longer able to "prevent spillage",[12] "remedy the cause or source of the spillage", or "contain and eliminate the spillage", each of which is required of a Permit Holder under Section 37 (1) of the BC Oil and Gas Activities Act. Further, FEI has committed to replacement of the pipeline as an integral part of its response to OGC Order 2013-25. Not undertaking pipe replacement could result in the OGC finding that FEI has failed to comply with a provision of the OGAA. As the alternative does not meet any of the objectives of the Project or the OGC requirements, FEI has concluded that this is not a feasible alternative.

26.1 Please provide an estimate of the increased costs that would likely be incurred for ongoing integrity management and increased leak inspection.

Response:

Please refer to the responses to BCUC IRs 1.2.2 and 1.7.1.

26.2 Please identify where in its response to OGC Order 2013-24 FEI committed to replacing the pipeline.

Response:

FEI's Engineering Assessment submission to the Oil and Gas Commission represents a commitment to pursue replacement of the existing NPS 20 Coquitlam Gate IP pipeline.

The Conclusion to that Assessment, on page 7, is excerpted below:

FortisBC's replacement plan for the subject pipeline, currently planned for submission to the BC Utilities Commission in 2014, appropriately addresses FortisBC's requirement as *a Permit Holder under Section 37 (1) (a) of the BC Oil and Gas Activities Act to "prevent spillage".*

The Engineering Assessment acknowledged that Section 45(1) of the Utilities Commission Act requires that a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the Commission a CPCN approving the construction or operation.

26.3 Did FEI consider the option of deferring the project beyond the current timeframe?

Response:

Please refer to the response to BCUC IR 1.2.2 for FEI's assessment that the existing NPS 20 Coquitlam Gate IP pipeline is nearing the end of its useful life and requires replacement. FEI has not identified any mitigation activities, other than replacement of the pipeline, which will prevent future leaks. Interim mitigation activities were established to allow for continued service until pipeline replacement.

Given the long lead times associated with planning and constructing a project of this magnitude, FEI did not consider the option of deferring the project beyond the current timeframe.

26.3.1 If yes, please clarify for how long FEI considered deferring the projects, and the reason(s) deferral was not considered appropriate.

Response:

Please refer to the response to CEC IR 1.26.3.

27.0 Reference: Exhibit B-1, Pages 33 and 34

3.2.2.2 Alternative 2 - Rehabilitate the Existing Coquitlam Gate IP Pipeline Operating at 1200 kPa

Advantages:

- The work could be scheduled over several construction seasons;
- No new running line would be required (except where inability to inspect due to depth would require a new section of pipeline to be installed), and
- It has one of the lowest capital costs compared to other alternatives.

Disadvantages:

- There are no methods to identify and locate girth weld locations from above ground, therefore, multiple digs and extensive excavation may be required to locate a girth weld;
- Direct inspection of the welds can only assess the pipeline condition over a very short length of pipeline at the weld location;
- It does not adequately mitigate potential safety risks to the public, plant, property and FEI personnel as a result of corrosion leaks with potential gas migration and accumulation until all of the pipeline welds have been exposed for inspection and evaluation;
- It does not enhance the operational flexibility of the Metro IP system;
- It does not enhance resiliency of the Metro IP system; and
- There are significant construction constraints associated with the urban nature of certain sections of this pipeline.

27.1 Over how many construction seasons would FEI expect to schedule the work for this option?

Response:

For Alternative 2, in order to rehabilitate the entire 20 kilometre length of the existing Coquitlam Gate IP pipeline, FEI would expect that the work could possibly be completed over a three to four year (seasons) timeframe. It is difficult to be more specific without a project construction and execution plan which would examine the project scope and risks. Hazards associated with completing rehabilitation work on a live natural gas pipeline in an urban environment would have to be considered in addition to developing a safe and efficient execution plan.

27.2 In what ways are the construction constraints associated with the urban nature of certain sections of the pipeline a particular disadvantage of this option relative to the other options.

Response:

Alternative 2 would involve the rehabilitation of the existing pipeline along its current alignment through Coquitlam, Burnaby and Vancouver in a high density, urban environment. The existing NPS 20 Coquitlam Gate IP pipeline was constructed in the 1950s, and the development and land use along the route has changed over time resulting in sections of the existing pipeline that are now in potentially difficult or impossible areas to access for rehabilitation purposes. Accessibility would be influenced by pipe depth, the presence of other utilities above and/or adjacent to the pipeline, and potentially other issues made more significant due to the heavy congestion around the pipeline.

Another challenge that would impact this Alternative arises from the fact that there are no methods to identify girth weld locations from above-ground. During past digs, multiple holes were often required to locate a girth weld. In addition, there was no way to verify that girth welds did not exist beneath unexcavated asphalt. While a conventional spacing is approximately 12 meters between girth welds (double-random pipe length), it is not considered uncommon for shorter segments of pipe to have been installed during the 1950s system construction.

The above factors will restrict FEI's ability to successfully complete a rehabilitation project described as Alternative 2. The other project Alternatives provide FEI the ability to locate a new replacement pipeline along an optimum running line and avoid construction constraints to a greater degree.

28.0 Reference: Exhibit B-1, Page 34

> This alternative does not fully mitigate potential future pipeline corrosion leaks because only the pipeline at each weld location would have been exposed for inspection, evaluation and repair. The estimated cost of this alternative is in the range of $154 million, with minimal potential benefits compared to the other long term strategy solutions, is very high. This alternative, while it is constructible, does not provide operational flexibility or system resiliency, or fully address pipeline risk. Consequently FEI has concluded that this is not a feasible alternative.

28.1 What would have typically been the expected service life of this segment of the pipeline?

Response:

Please refer to the response to CEC IR 1.8.1.

28.2 Are there any additional considerations other than potential corrosion leaks related to the age of the pipeline that would possibly need to be addressed in the future if the pipeline is not replaced?

Response:

Other than the non-preventable and increasing projected leak frequency due to external corrosion beneath the field-applied girth weld coating along the length of the pipeline, FEI has not identified other factors through its Integrity Management Program that would require replacement of the existing NPS 20 Coquitlam Gate IP pipeline.

28.2.1 If so, please identify any other considerations that may impact the longevity of the pipeline and explain in what ways they could serve to add costs or limit the remaining life of the pipeline.

Response:

Please refer to response to CEC IR 1.28.2.

28.3 Please confirm or otherwise explain that the repairs would likely satisfy FEI's commitment to the OCG that the pipeline was going to replaced.

Response:

As presented in Table 3-1 of Exhibit B-1 (page 41), FEI considers Alternative 2 as only partially meeting the objective of reducing pipeline risk, while not meeting the objectives related to operational flexibility and system resiliency. As such, FEI did not evaluate Alternative 2 as feasible in the context of the Application.

The rationale for the partial safety risk reduction was based on Alternative 2 comprising inspection, evaluation, and repair solely at the pipeline girth welds. As there are no methods for identifying girth weld locations from above-ground, it is possible that unexcavated pipe could contain girth welds or perhaps imperfections not associated with girth weld regions.

It is considered possible that Alternative 2, as described in Section 3.2.2.2 of the Application, may satisfy FEI's minimum obligation as a permit holder under the Oil and Gas Activities Act. This has not been discussed with the OGC as of the present time.

28.4 Please confirm or otherwise explain that FEI's commitment to the OCG does not preclude a Commission determination on the appropriate disposition of FEI's CPCN application.

Response:

FEI's commitment (or non-commitment) is not dispositive of the Commission's determination. The Commission determines whether a proposed project is in the public interest. Safe and reliable operation of a pipeline is a highly relevant factor in that determination.

29.0 Reference: Exhibit B-1, Pages 34 and 35

3.2.2.3 Alternative 3 - Replace (in-kind) the Existing Coquitlam Gate IP Pipeline Operating at 1200 kPa with a New NPS 20 Pipeline Operating at 1200 kPa

Advantages:

- This approach would replace the entire length of the existing pipeline with new pipe and would therefore reduce the probability of leaks;
- It would significantly reduce the risk of future corrosion related gas leaks;
- It would significantly reduce safety risks to the public, plant, property and FEI personnel as a result of leaks with potential gas migration and accumulation;
- It would minimize the risk of supply interruption to customers served by the Coquitlam Gate IP pipeline as a result of leaks;
- Due to common operating pressure, the pipeline would interface directly with the existing IP system and not require additional IP/IP interface stations; and
- It has one of the lowest capital costs compared to other alternatives.

Disadvantages:

- It does not provide sufficient operational flexibility to permit planned maintenance and repair of the Fraser Gate IP pipeline;
- It does not provide operational flexibility to the Metro IP system;
- It does not enhance resiliency of the Metro IP system;
- It does not mitigate the Metro IP system security of supply issues; and
- There are significant construction constraints associated with urban pipeline installation projects.

As discussed in section 3.1.2.3 the Company believes operational flexibility allowing for planned maintenance and repair is a critical requirement for continued safe, reliable and essential service to customers. This alternative does not provide the increased capacity necessary to facilitate planned outages for system work or provide system resiliency, therefore FEI has assessed this alternative not to be a prudent alternative, and consequently, not feasible.

29.1 Does FEI have a specific definition of what may be considered 'essential' service to customers?

<u>Response:</u>

FEI, as a public utility, has an obligation to "(a) provide, and (b) maintain its property and equipment in a condition to enable it to provide, a service to the public that the Commission considers is in all respects adequate, safe, efficient, just and reasonable." (See Section 38 of the Utilities Commission Act.) The word "essential" in this context reflects the Company's obligation to provide "adequate, safe, efficient, just and reasonable" service to the public who rely on its service.

29.1.1 If so, please provide FEI's definition and include any criteria which would deem the service to be essential.

Response:

Please refer to the response to CEC IR 1.29.1.

30.0 Reference: Exhibit B-1, Pages 35 and 36

3.2.2.4 Alternative 4 - Replace the Existing Coquitlam Gate IP Pipeline Operating at 1200 kPa with a NPS 24 Pipeline Operating at 2070 kPa

- Due to the higher operating pressure, the pipeline would interface indirectly with the existing IP system via additional IP/IP pressure reducing stations, creating a more complex system to operate;

- It does not provide full resiliency to the Metro IP system during mid-winter or design day conditions.

Although the level of increased capacity provided is insufficient to supply backfeed capability for a Fraser Gate IP outage during the colder days of winter (it does not provide full system resiliency), this alternative meets the other objectives. Therefore, on this basis, the Company investigated this alternative further.

30.1 Please elaborate on the increased complexity of operation and identify and quantify any cost impacts that may accrue.

Response:

Due to the higher operating pressure, IP/IP stations would be required to reduce the pressure from 2070 kPa to 1200 kPa at existing offtake points along the existing pipeline route. This would require an additional five stations connected to the network. These additional stations would introduce pressure regulation points and require monitoring and maintenance activities similar to what is currently undertaken throughout FEI's system. An incremental annual Operations and Maintenance cost of approximately $1500 has been forecast for each of the additional five stations.

30.2 What is the expected number of mid-winter days for which full resiliency would not be available? Please elaborate as appropriate.

Response:

Please refer to the responses to BCUC IRs 1.9.1.1 and 1.9.2.

30.3 Please provide an overview including quantitative definition of the design day conditions which are not met.

Response:

Please refer to the responses to BCUC IRs 1.9.1 and 1.9.2.

31.0 Reference: Exhibit B-1, Pages 36, 37 and 38

> ***3.2.2.5 Alternative 5 - Replace the Existing Coquitlam Gate IP Pipeline Operating at 1200 kPa with a NPS 36 Pipeline Operating at 1200 kPa***
>
> - It would supply the backfeed capacity to provide operational flexibility and some resiliency for the Metro IP system and mitigate risk of outage to 123,500 of the 171,000 customers served by the Fraser Gate IP pipeline.
>
> - It does not provide full resiliency to the Metro IP system and could result in a loss of supply to approximately 47,500 customers during the colder days of winter.

31.1 Why is the potential for the loss of supply limited to 47,500 customers during the colder days of winter under this Alternative?

Response:

The 47,500 customers in this scenario are potentially at risk in the event that a failure interrupts supply at Fraser Gate station and the Metro IP system is fed entirely from Coquitlam Gate. The larger NPS 36 pipeline operating at 1200 kPa in this alternative could provide pressures sufficient for most areas of the Metro IP system except for the stations nearer Fraser Gate serving south Burnaby and the stations feeding the Point Grey area of Vancouver as these stations would be near the tail end of the system.

31.2 In what area are the 47,500 customers located that would be subject to risk of outage?

Response:

Please refer to the response to CEC IR 1.31.1.

31.3 Please confirm or otherwise explain that the Alternative would not supply full system resiliency during design day conditions.

Response:

Confirmed. An outage of up to 47,500 customers in South Burnaby and the west side of Vancouver could occur in the event that supply from the Fraser Gate Station was lost.

32.0 Reference: Exhibit B-1, Page 38

> ***3.2.2.6 Alternative 6 - Replace the Existing Coquitlam Gate IP Pipeline Operating at 1200 kPa with a NPS 30 Pipeline Operating at 2070 kPa***
>
> This alternative has an AACE Class 3 Project Capital Cost Estimate $201.282 million in 2014 dollars[15].
>
> Instead of replacing the existing Coquitlam Gate to 2nd & Woodland pipeline in-kind, a similar approach as outlined above could be adopted to replace the existing pipeline in its entirety with new larger diameter pipe operating at a higher pressure with sufficient capacity to establish full Metro IP system resiliency.
>
> [15] The equivalent As-spent cost including abandonment/demolition cost but excluding AFUDC is $232.985 million, AFUDC of $12.572 million with the total cost being $245.557 million.

32.1 Would it be feasible to provide additional system resiliency to any of the other options through the acquisition of moveable LNG regasification plants and deployment during unscheduled events?

Response:

It would not be feasible to provide additional system resiliency to any of the other options through the acquisition of moveable LNG regasification plants.

32.1.1 If not, please explain why not.

Response:

The volumes that would be required to provide additional system resiliency are much too great for a moveable LNG regasification plant. For example, the volumes required for a full day under peak conditions to support the community of West Vancouver, representing a small portion of the potential outage areas determined in the other alternatives, would be approximately 24 TJ. The capacity of an LNG road tanker is approximately 1 TJ and the existing Tilbury plant could deliver one tanker every two hours. This would not be timely and the volume would not be adequate during an unscheduled event. A fleet of tankers and high capacity/high pressure vapourization equipment would be required, but which would be costly, used infrequently and require continuous maintenance and testing.

The source of LNG supply for this option would be from FEI's Tilbury existing plant. The volumes that would be removed from the plant would greatly diminish its capability to provide peak shaving service to the transmission system.

32.1.2 If yes, please clarify if FEI has considered this option or not.

Response:

Please refer to the response to CEC IR 1.32.1.1.

32.1.3 If yes, what advantages and disadvantages does FEI anticipate with such an option?

Response:

FEI has not considered this option as it is not consider viable. Please refer to the response to CEC IR 1.32.1.1.

32.1.4 Could such an option enhance FEI's system resiliency and flexibility for other circumstances? Please explain.

Response:

Not appreciably. FEI has used a moveable LNG regasification facility for scheduled work to avoid small distribution pressure outages. The practical delivery volumes, as outlined in the response to CEC IR 1.32.1.1, are far below those that would be required to support moderate or larger area outages in winter conditions.

33.0 Reference: Exhibit B-1, Page 43

Table 3-2: Coquitlam Gate IP Project Financial Comparison

	Alternative 4 Install NPS 24 pipeline at 2070 kPa	Alternative 5 Install NPS 36 pipeline at 1200 kPa	Alternative 6 Install NPS 30 pipeline at 2070 kPa
AACE Estimate Accuracy	*Class 4*	*Class 4*	*Class 3*
Total Direct Capital Cost excl. AFUDC & includes Abandonment / Demolition (2014$millions)	175.004	205.448	201.282
Total Direct Capital Cost excl. AFUDC (As-spent $millions)	202.481	238.178	232.985
AFUDC (as spent $millions)	11.054	12.309	12.572
Total As-spent includes Abandonment / Demolition & AFUDC ($millions)	213.535	250.487	245.557
Annual incremental gross O&M (2014$millions)	0.055	0.020	0.055
Levelized Rate Impact – 60 Yr. ($ / GJ)	0.087	0.103	0.101
PV Incremental Cost of Service – 60 Yr. ($millions))	259.659	306.480	300.513

[16] Includes project management, engineering, permits, materials procurement, construction, commissioning and contingency. For purposes of comparing alternatives, the development costs and application costs have been excluded from the capital costs in Table 3-2. These costs are the same in Alternative 4, 5 and 6 and are fully amortized before 2019 and do not impact the 2019 and 60 year average Levelized rate impact..

33.1 Please confirm or otherwise clarify that a Class 3 Estimate includes project definition in the range of 10-40%.

Response:

Confirmed.

33.2 Please provide FEI's estimate of the level of project definition that was available when Alternative 6 was estimated.

Response:

Alternative 6 was developed to an AACE Class 3 level of project definition in the range 10% to 40%.

33.3 Please confirm or otherwise clarify that a Class 4 Estimate includes project definition in the range of 1% to 15%?

Response:

Confirmed.

33.3.1 Please provide FEI's estimate of the level of project definition that was available when Alternatives 4 and 5 were estimated.

Response:

Alternatives 4 and 5 were developed to an AACE Class 4 level of project definition in the range of 1% to 15%.

33.4 What are the estimated development costs and application costs?

Response:

Please refer to Exhibit B-1, Table 5-4: Forecast Deferred Development Costs ($2.004 millions) and Table 5-3: Forecast Deferred Regulatory Application Costs ($1.047 millions) for estimated costs associated with the preferred pipeline alignments as currently indicated in the CPCN Application. Should the preferred alignment change as a result of the current analysis of Lougheed Highway through Burnaby, updated development and application costs will be reflected in the evidentiary update provided to the Commission.

33.5 Please provide an analysis of the operating costs for each of the three alternatives.

Response:

The O&M costs shown are based on historical averages which have then been adjusted for the changes associated with each option. The historical costs are primarily made up of Preventative and Inspection work (approximately 80%) and Corrective work, i.e repairs (approximately 20%). The split varies from year to year based on equipment performance. The costs can further be broken down by the labour / material split which has averaged approximately 90% labour / 10% material.

Alternatives 4 and 6 have the facilities at 2nd & Woodland being demolished and a new station built which would require FEI to find an alternate location for contract workers at a new leased location in the same area.

	$000's (2014$)		
	Alternative 4: 24 NPS @ 2070 kPa	Alternative 5: 36 NPS @ 1200 kPa	Alternative 6: 30 NPS @ 2070 kPa
Labour:CTS Station Mtnce. - PSV, Inspection Valve Mtnce., Instrument Mtnce., Meters Mtnce.	$ 15.1	$ 7.9	$ 15.1
Labour: Corrective Valve Mtnce.	10.0	10.0	10.0
Contractor: Vegetation Mtnce., Leak Survey	3.2	3.2	3.2
Facilities	27.6	-	27.6
Total O&M (2014$)	$ 55.9	$ 21.1	$ 55.9

34.0 Reference: Exhibit B-1, Page 44

Table 3-3: Coquitlam Gate IP Project Financial and Operational Risk Comparison

		Alternative 4 Install NPS 24 pipeline at 2070 kPa	Alternative 6 Install NSP 30 pipeline at 2070 kPa
1	Operational Risk Reduction (%)	0	100
2[17]	Remaining Operational Risk (2014$millions / year)	2.456	0
3	PV Remaining Operational Risk – 60 Yr[18] ($millions)	38.880	0
4	PV Incremental Cost of Service – 60 Yr ($millions)	259.659	300.513
5	PV Remaining Operational Risk + PV Incremental Cost of Service –60Yr ($millions)	298.539	300.513

[17] See section 3.1.3.4.

[18] PV Remaining Operational Risk – 60 Year was derived by applying the formula for the present value of an annuity to the annual remaining operational risk of $2.456 million using FEI's after tax weighted average cost of capital of 6.14%; PV = $2.456 x [(1 – (1 + k)$^{-n}$) / k] Where k = 6.14% and n = 60 years.

34.1 Why did FEI use 60 years for assessing the present value?

Response:

Please refer to the response to BCUC IR 1.22.10.

34.2 Does FEI typically use 60 years for assessing the present value of existing 50-60 year old pipeline alternatives?

Response:

FEI has used 60 years for assessing the present value of the alternatives for previous CPCN applications for pipeline projects such as Fraser River South Arm, Huntingdon Station Bypass, and Kootenay River Crossing.

34.2.1 If no, please explain why FEI has made a change in this instance.

Response:

Please refer to the response to CEC IR 1.34.2.

35.0 Reference: Exhibit B-1, Page 46

> An analysis of the PV of the 60 year cost of service shows that Alternative 4 is $40.854 million less than Alternative 6 and that the differential in terms of a 60 year Levelized Rate Impact between the two is $0.014 per GJ. Based on an average annual consumption of 95 GJ per residential customer, this would result in an annual cost difference between the two alternatives of $1.33 per customer.

35.1 Please provide the average annual cost difference for each of the two alternatives for each of the Commercial rate classes.

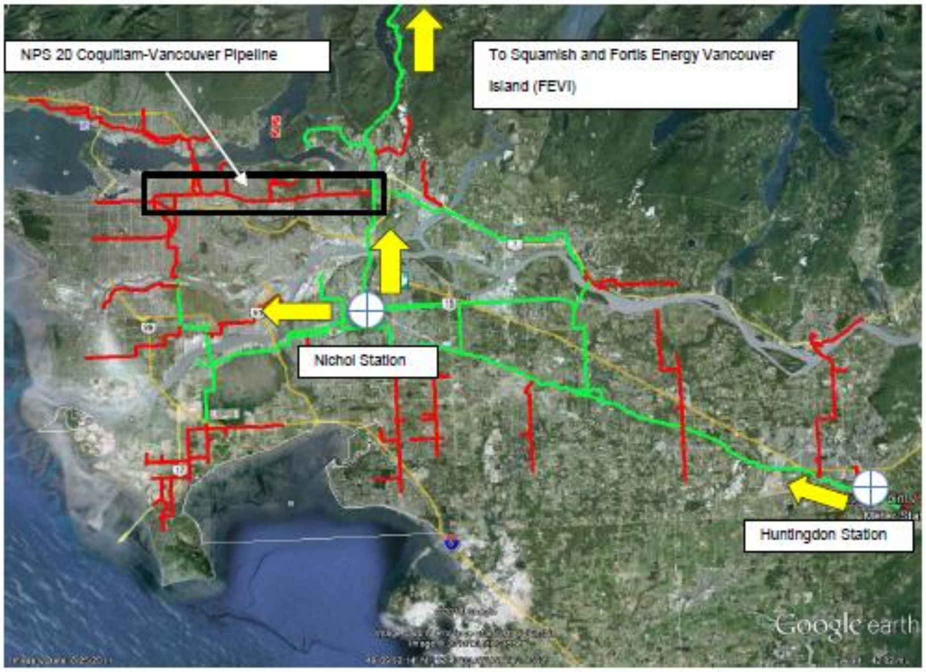
Response:

The following table provides the average annual cost difference between Alternative 4 and Alternative 6 for each of the Commercial rate classes.

	Alt. 4 vs. Alt. 6 60 Yr. Levelized Rate Difference	Typical / Average Consumption Rate GJ	Annual Bill Variance
Small Commercial	$ 0.014	334	$ 4.68
Large Commercial - Sales	$ 0.014	3,769	$ 52.77
Large Commercial - T-Service	$ 0.014	5,589	$ 78.25

36.0 Reference: Exhibit B-1, Pages 47 and 49

Figure 3-3: Coquitlam Gate IP Project FEI Lower Mainland Gas Supply Network



Source: FEI data overlaid on Google Earth mapping

TP pipelines operating at greater than 2070 kPa

IP pipelines operating from 700 kPa to 2070 kPa

> The Coquitlam Gate IP pipeline is the 'backbone' of the east to west IP distribution network which supplies district stations and single point of use industrial customers connected along the route corridor from Coquitlam to Vancouver (see Figure 3-4). The Fraser Gate IP pipeline is the 'backbone' of the south to north IP distribution network. Both pipelines interconnect in Vancouver at East 2nd & Woodland and East 2nd & Slocan Street stations. This interconnectivity facilitates a balanced gas flow between both pipelines, especially in the event of a disruption to normal flow regimes.

36.1 Will there likely ever be any reason to upgrade the north south backbone (Fraser Gate IP) pipeline to 2070 kPa?

Response:

Not at this time based on the information available. Based on current forecasts, there would not likely be any reason for upgrading the Fraser Gate IP pipeline to 2070 kPa. However, as in the case of the proposed Coquitlam Gate IP Project, if a replacement of the Fraser Gate IP pipeline was required for reasons other than capacity, consideration of any benefits of a pressure upgrade alternative would be considered at that time.

36.1.1 If yes, please provide an overview of the conditions that might require an upgrade in this segment of the pipeline.

Response:

Please refer to the response to CEC IR 1.36.1.

36.1.1.1. When would these conditions possibly occur?

Response:

Please refer to the response to CEC IR 1.36.1.

37.0 Reference: Exhibit B-1, Page 51

> District stations and industrial customers, which are located in proximity to the existing Coquitlam Gate IP pipeline and connected by relatively short IP laterals, will undergo station and lateral pipeline upgrades to meet the higher MOP of the proposed Coquitlam Gate IP pipeline. In situations where the district stations or industrial load is located remotely, and connected via a longer IP lateral, then a new station will be constructed at the interface between the Coquitlam Gate IP pipeline and the existing IP laterals to reduce the pressure from the Coquitlam Gate IP pipeline MOP of 2070 kPa to the lateral line MOP of 1200 kPa. This solution is more cost effective and will result in a lower overall impact by avoiding the cost and construction associated with unnecessarily replacing the existing longer lateral pipelines with a new pipeline through congested urban neighbourhoods. These IP/IP pressure reduction stations will comprise pressure regulating equipment housed in a compact underground vault similar to the existing district stations.

37.1 Please confirm that there will be no or very limited impact on Industrial customers connected either by short or longer IP laterals.

Response:

Confirmed.

38.0 Reference: Exhibit B-1, Page 53

3.3.3.3.1 DESIGN PARAMETERS

The Coquitlam Gate IP pipeline and lateral pipeline upgrade main design parameters are listed in Table 3-5.

Table 3-5: Coquitlam Gate IP Pipeline Specification Details

Details	Values
Pipeline Length	19,700 m
Pipeline Outside Diameter/Nominal Pipe Size)	762 mm/NPS 30
Maximum Operating Pressure (MOP)	2,070 kPa (300psi)
Pipeline Material Grade/Specified Minimum Yield Strength (SMYS)	359 MPa (X52)
Maximum Hoop Stress (as a % of SMYS)	<30%
Pipeline Buried Depth (min)	1.2m to top of pipe
Design Temperature	50 degC
Pipe External Coating	Fusion Bonded Epoxy (FBE)

As detailed in section 3.3.3.2.3 some of the existing IP/DP district stations which are located in proximity to the existing Coquitlam Gate IP pipeline and connected by relatively short IP lateral pipelines, will undergo station and lateral pipeline upgrades to suit the higher MOP of the proposed Coquitlam Gate IP pipeline. These laterals will be constructed to the same pipe specification as detailed in Table 3-5. The diameter and approximate lengths of these laterals are detailed in Table 3-6.

38.1 Will the pipeline include girth welds with similar field applied coating as to that which is resulting in corrosion and leaks?

Response:

No, the proposed field applied coating at girth welds for the new pipeline will be liquid applied 100% solids epoxy. This field applied coating has equivalent properties in terms of performance to the proposed factory applied fusion-bonded epoxy (FBE) coating. Epoxy coatings are considered "non-shielding" in the case of failure or loss of adhesion. Therefore, unlike the existing NPS 20 Coquitlam IP pipeline field applied coating, cathodic protection will be successful in controlling corrosion on the proposed NPS 30 pipeline where coating damage or degradation may occur over the life of the new pipeline.

38.1.1 If yes, how will FEI ensure that the field applied coating does not result in similar issues as are occurring presently?

Response:

Please refer to the response to CEC IR 1.38.1.

39.0 Reference: Exhibit B-1, Page 58

> 3.3.3.3.5 In-Line Inspection
>
> In-line inspection (ILI) is a process which utilizes the pipeline gas flow and pressure characteristics to propel an inspection tool within the pipeline. There are a number of types of in-line inspection tools that can be used to detect and size a variety of pipeline anomalies, including corrosion and existing mechanical damage. To facilitate ILI, the pipeline design must incorporate certain features and mechanical components including:
>
> - Pipeline bends with radii at least 3 to 5 times the pipeline diameter;
> - Full bore mainline block valves to permit unrestricted passage;
> - Launcher at the pipeline inlet for tool insertion and to control the propulsion through the pipeline; and
> - Receiver at the pipeline outlet to receive the in-line inspection tool.
>
> FEI has determined that due to the longevity of steel pipelines, it is appropriate to design the Coquitlam Gate IP pipeline with future ILI capability. This will enable the cost effective and targeted mitigation of specific pipeline hazards (i.e. corrosion) over the service life of the new asset.

39.1 What are the different types of inline inspection tools?

Response:

In-line inspection (ILI) tools generally fall into three main types: geometry, metal loss and crack detection. When used with an inertial mapping unit the tools can be used to map the pipeline in three dimensions.

39.2 Does FEI use in-line inspection tools for other pipelines in its system?

Response:

FEI uses in-line inspection tools in its transmission pressure pipeline system.

39.2.1 If no, please explain why not.

Response:

Please refer to the response to CEC IR 1.39.2.

39.2.2 If yes, please identify which tools FEI currently uses and why.

Response:

FEI runs both geometry and metal loss tools to inspect its transmission pressure pipeline system as part of FEI's Integrity Management Program. Geometry tools are run in the pipelines to locate, identify and size dents, ovalities, ripples, wrinkles, buckles, bends and bore restrictions. Metal loss tools are run in the pipeline to locate, identify and size metal loss (corrosion), manufacturing, and gouge anomalies. Both geometry and metal loss tools are run with inertial mapping systems and are used to map the pipeline in three dimensions and identify and size pipe movement (between successive inspection runs). These tools are also able to identify welds, fittings, and other appurtenances on the pipeline.

39.3 Will the pipeline design allow for all types of ILI tools to be used, or are there some that will not be available for use?

Response:

Currently only geometry and metal loss tools are available which can be run in gas pipelines that operate at 2070kPa. Tools with this low pressure capability are only available from a limited number of vendors and are relatively new to the market. Low pressure crack detection tools that can be run in gas pipelines are not currently available.

39.4 Please confirm or otherwise explain that the expected service life of the asset is 60 years or longer.

<u>Response:</u>

Please refer to the response to CEC IR 1.8.1.

40.0 Reference: Exhibit B-1, Page 58

Coating Protection

External coatings provide the first level of defence against external corrosion of buried steel piping, and are required by the CSA Z662 standard. Coating protection involves the application of a layer of factory applied corrosion resistant material to the outside of the pipe after manufacture and prior to delivery for construction. There are different coating materials available depending on the specific requirements. Fusion Bonded Epoxy (FBE) has been selected as the most appropriate coating for the Coquitlam Gate IP pipeline replacement. FBE material is a high quality durable, industry accepted coating and has been selected due to the pipeline's urban location and the following requirements:

- Due to the potential presence of hydrocarbons along the route alignment corridor the costing must be resistive to hydrocarbon deterioration;
- Due to the highly constrained working area during construction requiring multiple pipe handling scenarios the coating must resist mechanical damage during construction and installation; and
- Due to the urban pipeline location the coating must be resistive to mechanical damage after installation and backfill to minimize future excavations for damage repair.

40.1 Is there a significant difference in price between FBE and other industry accepted coating? Please explain and provide quantification if there are significant cost differences.

Response:

Please refer to the response to BCUC IR 1.11.4.1.

40.2 Has FEI successfully used FBE coating before?

Response:

Confirmed. FEI has successfully utilized FBE coating on most large diameter pipeline projects over the last 15 years. These projects include the Southern Crossing Pipeline, the Whistler IP Pipeline, and the Fraser River South Arm NPS 20 and NPS 24 crossing upgrade.

FBE pipeline coatings are industry standard for large diameter pipelines, and have a successful performance history.

40.3 What, if any, are the disadvantages of using FBE?

Response:

FEI does not believe there are any disadvantages to using FBE as the factory applied pipeline coating material.

40.4 What is the difference between FBE coating and the field applied coating on the current pipeline which is failing?

Response:

The field applied coating on the existing pipeline is coal tar enamel. Coal Tar is derived from the coking of coal, producing a coal tar pitch which is then mixed with inert fillers to produce the enamel. The enamel is heated to a liquefied state to be applied as a coating. Once cooled, the enamel forms a hard, brittle, thick film on the pipe surface. Due to environmental and health concerns, the use of coal tar enamels in the oil and gas pipeline industry was discontinued around the late 1980s. Factory applied coal tar enamel coatings have proven to be very effective. However, field applied coal tar enamel does not have the same performance history. This is likely due to poor or improper application techniques, as inspection and quality control programs for pipeline construction in the past were far less rigorous than modern day standards.

FBE coatings are typically applied in a controlled factory environment. FBE is produced from organic epoxy resins and made into a powder form. It is electrostatically applied to a heated pipe surface, where it melts and flows to form a monolithic, relatively thin film. FBE has excellent adhesion to abrasive blasted steel as well as excellent chemical resistance. Typically liquid applied epoxy is used for field application on girth welds. The FBE and liquid epoxies utilize the same organic epoxy resins, have the same performance characteristics, and are compatible with each other. Current day coating specifications include a high level of inspection and quality control, to ensure factory and field applied coatings will meet long term performance requirements.

41.0 Reference: Exhibit B-1, Page 59

> **Cathodic Protection**
>
> Cathodic protection is generally regarded as a secondary defense against external corrosion, used in conjunction with coatings. It is also a requirement of the CSA Z662 standard. Corrosion control of the Coquitlam Gate IP pipeline will be achieved via the protective external coating described previously and an impressed current cathodic protection system. Cathodic protection of the existing Coquitlam Gate IP pipeline is supplied via an impressed current cathodic Protection (CP) system, comprising rectifiers and deep anode beds. These are located at 2nd Avenue & Skeena Street and at Underhill Drive & Broadway. To facilitate cathodic protection system management and its effective performance, the existing pipeline is separated into two sections via an electrical isolation fitting installed at 2nd Avenue & Boundary Road. The impressed current system located at 2nd Avenue & Skeena Street was originally installed in 1964 and had replacement anode beds installed in 1976 and 1994. This impressed current system now provides protection to the Coquitlam Gate IP pipeline from 2nd Avenue & Boundary Road to 2nd Avenue & Woodland Street. The impressed current system located at Underhill Drive & Broadway was installed in 1989, with a replacement anode bed installed in 2003. This impressed current system provides protection to the Coquitlam Gate IP pipeline from 2nd Avenue and Boundary to Coquitlam Gate station. It is expected that the existing CP system could be used to provide protection to the new Coquitlam Gate IP pipeline; this will be confirmed during detailed design.

41.1 What issues could arise such that the Cathodic Protection system would not be adequate?

Response:

Detailed engineering decisions, including final route selection, will impact the ability to leverage the existing CP system. Proximity of the new NPS 30 pipeline from existing cathodic protection assets will be a primary influencing factor.

Please also refer to responses to BCUC IRs 1.11.5 and 1.11.6.

41.2 What would be the alternative solution in the event that the existing CP system could not be used?

Response:

The installation of new CP equipment would be required in the event that the existing system could not be used.

Please also refer to response to BCUC IR 1.11.6.

42.0 Reference: Exhibit B-1, Page 59

3.3.3.3.7 INTEGRITY MONITORING

Similar to the existing pipeline, the integrity of the new Coquitlam Gate IP pipeline will be managed within FEI's Integrity Management Program (IMP). The IMP is a corporate-level management system for identifying and mitigating hazards to the system that have the potential to result in failure with significant consequences. Activities include:

- Monitoring of the cathodic protection system in accordance with CSA Z662, CGA OCC-1, and industry practice. These monitoring programs are established and documented within Company standards; and
- Third-party damage prevention activities, including a permits & inspection process and public safety awareness programs.

42.1 Will the Integrity Management Program costs remain similar to that for the existing pipeline, or will these changes?

Response:

Integrity Management Program (IMP) costs comprise such activities as valve maintenance, leak surveys, cathodic protection system monitoring, and integrity digs where warranted. The IMP also includes such items as employee training and competency programs, standards development and updates, and public safety awareness activities.

FEI has included an estimate of "Annual incremental gross O&M" for the proposed NPS 30 pipeline (Alternative 6) in Table 3-2 page 43 of the Application. A further analysis of these incremental costs has been provided in the response to CEC IR 1.33.5.

Although IMP costs are expected to vary over an asset's lifecycle, FEI has not currently identified incremental Integrity Management Program costs beyond those already reported.

42.1.1 If the Integrity Management Program cost are expected to change, please explain and provide quantification where available.

Response:

Please refer to the response to CEC IR 1.42.1.

43.0 Reference: Exhibit B-1, Page 60

3.3.3.4.1 COQUITLAM GATE STATION

The required upgrades to the existing Coquitlam Gate station are listed below and presented in greater detail on the engineering drawings attached in Confidential Appendix A-13.

- Remove the existing pressure control system consisting of filtration, heating, metering, and control/regulation along with associated piping (the existing system is not designed to handle the new gas flow rates through the station to the NPS 30 Coquitlam Gate IP pipeline);
- Remove the existing mechanical equipment: gas heat exchanger and glycol boiler system, filter vessels, and equipment and piping associated with the existing pressure reduction system;
- Remove the existing pressure letdown building which includes deconstruction of the below-ground building foundation;
- Remove the existing glycol boiler system building;
- Remove the existing instrumentation building;
- Install a new TP/IP pressure control system TP 4020 kPa to IP 2070 kPa consisting of filtration, heating, metering and control/regulation (suitable for the new gas flow rates);
- Install a new IP/IP pressure control system IP 2070 kPa to IP 1200 kPa consisting of filtration, heating, metering and control/regulation;
- Install a new heat exchanger for the TP/IP pressure control system;
- Install a boiler building housing three glycol boiler systems for the heat exchangers;
- Install a new pig launcher;
- Install a building for the TP/IP pressure control system;
- Relocate the existing storage building to the southwest corner of the plot plan;
- Install a new instrumentation building; and
- Relocate the uninterruptable power supply system, standby generator, and instrument air system.

43.1.1 Will FEI dispose of or re-use those items at either station that are not able to be re-located? Please explain.

Response:

FEI will consider the re-use potential for those items at either station that are not available to be re-located and re-used within this Project. The items will be assessed for re-use depending on their condition, the need for the item, and the functionality of the item. Items that cannot be re-used will be recycled or disposed of as appropriate.

44.0 Reference: Exhibit B-1, Page 61

> 3.3.3.4.5 RTU/SCADA AND COMMUNICATION
>
> New Remote Telemetry Units (RTU) and Supervisory Control and Data Acquisition (SCADA) systems will be installed at Coquitlam Gate and East 2nd & Woodland stations including communications hardware and Uninterruptible Power Supplies (UPS). Communications with the FEI Control Centre will be via cellular phone and telephone line for redundant communications. All field instruments including fire and gas detectors, Emergency Shut Down (ESD) valves will be wired to the new RTU/SCADA systems. The programming and configuration of these systems will be executed by FEI Electrical & Controls (E&I) group.

44.1 Why are new RTUs and SCADA systems required?

Response:

The requirement for a new station at East 2nd & Woodland to interface the NPS 30 Coquitlam Gate IP pipeline with the Fraser Gate IP pipeline will require the installation of a RTU and SCADA system at this site.

The Coquitlam Gate station will be upgraded with new mechanical, electrical and instrumentation equipment to process the higher station flow rates and operating pressure, and will therefore require new RTU and SCADA systems to provide appropriate onsite process and systems control, monitoring and feedback to FEI Gas Control.

45.0 Reference: Exhibit B-1, Page 63

> The existing NPS 20 Coquitlam Gate IP pipeline will be abandoned in place once the new pipeline is in service. It is not possible to abandon or remove the existing NPS 20 IP pipeline prior to installation and commissioning of the new NPS 30 IP pipeline in its entirety. Supply must be maintained to all customers. Therefore, to minimize the risk of supply interruption from either a corrosion leak or damage caused by the parallel construction of the new NPS 30 IP pipeline, the ability to isolate and repair a section of the existing NPS 20 IP pipeline and backfeed from either the Fraser Gate or Coquitlam Gate stations must be maintained.
>
> In accordance with CSA Z662-11 and the Company's internal standards, the pipeline will be abandoned in the following stages:
>
> - Emptied of service fluids;
> - Purged and appropriately cleaned;
> - Physically separated from any in-service piping;
> - Cut and capped below grade; and
> - No longer cathodically protected or maintained according to normal maintenance schedules.
>
> The pipeline will be sectioned into shorter segments, and all open ends plugged or sealed with watertight closures in order to minimize potential gas or water migration. Sections of the abandoned pipe may be filled with a structural grout to prevent pipeline collapse and ensure the integrity of nearby drainage systems or other infrastructure. All recorded data pertaining to the abandoned pipeline, including location and depth of cover, will be maintained on file.

45.1 What, if any, are the environmental impacts of abandoning the pipeline in place?

Response:

FEI has selected abandonment in place as the optimum end-of-life solution for the NPS 20 Coquitlam Gate IP pipeline, and the considerations informing this decision are presented in the response to CEC IR 1.45.4. The urban location of the NPS 20 pipeline route, along with its operational history of carrying sweet, dry natural gas, presents less environmental risk when abandoning in place, compared to a liquid hydrocarbon pipeline. Below, FEI has discussed the typical environmental impacts of abandoning a pipeline in place, and which of these impacts may be applicable to the NPS 20 Coquitlam Gate IP pipeline.

According to Det Norske Veritas "Pipeline Abandonment Scoping Study" prepared for the National Energy Board (NEB) in 2010, the potential environmental impacts of abandoning a pipeline in place include the following:

a) Soil and groundwater contamination;

b) Soil resources;

c) Creation of water conduits; and

d) Pipeline water crossings.

The existing NPS 20 Coquitlam Gate IP pipeline carries sweet, dry natural gas, and has throughout the entirety of its operating life. Since no liquid hydrocarbons have ever been transported in this pipeline, the potential sources of soil and groundwater contamination are limited to the pipeline coatings and their degradation products, any liquids that may have been inadvertently carried by the pipeline during its operating life (e.g. compressor oil), and the potential for corroded pipe to act as a conduit, transporting any contaminants present in the surrounding soil to other points along the pipeline.

To minimize these risks, after commissioning of the replacement NPS 30 IP pipeline, the existing NPS 20 pipeline will be cut into shorter segments which will then be cleaned and capped to minimize any potential sources of contamination. Since the NPS 20 Coquitlam Gate IP pipeline is used to transport sweet, dry, natural gas and is operated in a clean state, the risk of contaminants being left in the pipeline is minimal, and the potential for soil and/or groundwater contamination from the cleanliness of the pipeline will not be a factor for this Project.

The Det Norske Veritas study identifies several other possible sources of contamination and contamination risks, which are specific to pipelines that previously transported liquid hydrocarbons and are therefore not applicable to this pipeline including pipe treatment chemicals, substances in the hydrocarbon stream, and historical leaks and spills of product not cleaned up to current standards. The Det Norske Veritas study also states that "Contamination risks are arguably greatest for pipelines abandoned in-place…. This is because the pipe will eventually be perforated by corrosion, allowing any contaminants left in the pipeline to migrate into the surrounding environment…. Potential also exists for corroded pipe to act as a water conduit, transporting any contaminants present to other points along the pipeline." These may be correct statements for pipelines used to transport liquid hydrocarbons that are not left in a clean state; however, as previously discussed, this is not applicable to this pipeline.

Erosion can be caused by pipeline abandonment in-place in two ways: corrosion perforated pipe can conduct water along the length of the pipeline to exit the pipeline in new locations and, soil subsidence due to pipeline collapse can create water conduits able to intercept and channel drainage along the pipeline alignment. Furthermore, following pipeline abandonment, water crossings remain a key environmentally sensitive location along the pipeline alignment. Abandoned pipelines may corrode and fail at watercourse crossings. Pipe can also become exposed at watercourse crossings due to stream bank erosion and migration. However, there are very few water course crossings along this pipeline alignment where this is a concern. The majority of the water course crossings occur in roadways where the water course is already contained within a culvert and the pipeline crosses the water course either over or under the existing culverts. To mitigate these risks, as previously stated, the pipeline will be cut into shorter sections, filled with a structural grout (where warranted) to prevent pipeline collapse and all open ends will be capped and sealed to prevent abandoned sections of pipe from acting as a water conduit and causing erosion.

45.2 Please provide a list of recognized concerns related to abandoning pipeline in place.

Response:

Please refer to the responses to CEC IRs 1.45.1 and 1.45.4.

45.2.1 Is it more common to abandon pipelines in place, remove all the pipeline, or remove portions of the pipeline? Please explain.

Response:

Please refer to the response to CEC IR 1.45.4.

45.3 Are there regulations governing the removal and abandonment of pipelines in BC and/or specifically within the lower mainland?

Response:

Please refer to the response to CEC 1.45.4.

45.3.1 If yes, please identify which bodies regulate pipeline abandonment and removal and where the regulations may be found.

Response:

Please refer to the response to CEC IR 1.45.4.

45.4 Are there site specific considerations that limit the ability of the pipeline to be removed after the commissioning of the other pipeline?

Response:

Due to the urban location of the NPS 20 Coquitlam Gate IP pipeline, there are a number of site specific considerations, and other factors, that ultimately influence the abandonment decision for this pipeline. It is FEI's understanding that pipeline abandonment in place (as opposed to abandonment through removal) to be the most common form; however, it is the specific requirements pertaining to a particular pipeline that would dictate whether the pipeline should be abandoned in place, removed or partially removed.

Regulations governing the removal and abandonment of pipelines in BC include CSA Z662 and the Oil and Gas Activities Act (OGAA). The BC Oil and Gas Commission regulates pipeline abandonment and removal under OGAA, in particular under section 40. Requirements are prescribed under section 11 of the Pipeline Regulation. FEI must also comply with all federal and provincial regulatory requirements including the Environmental Management Act and associated regulations. CSA Z662-11 Clause 10.16.1 specifically states:

> *"The decision to abandon a section of piping, in place or through removal, shall be made on the basis of an assessment that includes consideration of current and future land use and the potential for safety hazards and environmental damage to be created by ground subsidence, soil contamination, groundwater contamination, erosion, and the creation of water conduits."*

With regard to the NPS 20 Coquitlam Gate IP pipeline, the decision to abandon the pipeline in place was based on a number of factors including site specific considerations that limit the ability of the pipeline to be removed after commissioning of the replacement NPS 30 Coquitlam Gate IP pipeline.

FEI's abandonment decision was informed during the NPS 30 Coquitlam Gate IP pipeline route selection phase of the Project. The routing process acquired data pertaining to the terrain, urban environment, including residential, commercial and industrial development, environmentally sensitive locations, roads and traffic and third party above and below ground infrastructure from Coquitlam Gate station in Coquitlam to East 2nd & Woodland station in Vancouver. This informed the NPS 30 pipeline routing in terms of identifying sub-surface constraints and construction challenges along the route corridor and, because both the existing NPS 20 and replacement NPS 30 pipelines would be located within the same road allowance, or offset a couple of blocks, this understanding also informed FEIs decision with regard to abandonment of the NPS 20 pipeline. Fundamentally, the impacts from removal of the existing NPS 20 pipeline would result in a second major linear disturbance through the same communities and compound the impacts from the NPS 30 pipeline construction immediately prior. Overall, the negative impacts in terms of Health and Safety, Community and Stakeholder and Environment would be significantly greater. The site specific and general considerations informing the abandonment decision include:

- The gas flow in the existing NPS 20 pipeline must be maintained to supply customers while the NPS 30 IP pipeline is constructed and commissioned. Therefore, it is not possible to remove the existing NPS 20 IP pipeline prior to, or in conjunction with, the construction and installation of the proposed NPS 30 pipeline. The abandonment construction would occur after the NPS 30 pipeline construction, effectively doubling the construction impacts to the municipalities of Coquitlam, Burnaby and Vancouver;
- Unlike construction of a new pipeline, which targets the optimum location to effect construction as efficiently and safely as possible while minimizing impacts, even in a highly urbanized environment, the removal of the NPS 20 pipeline would have to contend with any obstacle encountered on the NPS 20 running line and utilize any available or non-standard construction technique to remove the decommissioned pipe;
- Considering the consistent urban nature of the pipeline route and the development in, around and over the NPS 20 pipeline in the intervening years since installation, in terms of buildings, paving, infrastructure and other structures and utilities, there would be significant logistical and construction challenges with removing the NPS 20 pipeline along the majority of the alignment;
- Removal of the NPS 20 pipeline from parks and sensitive environmental areas (e.g. watercourse crossings) could result in environmental impacts;
- As the majority of pipeline is located beneath active roadways, removing the existing NPS 20 pipeline would incur traffic impacts;

- Removing the pipeline from beneath roads, railways and other utilities, particularly where the pipeline is buried deep, or overlain by third party assets, increases the risk for damage to these third party assets, and disruption to services provided by these to homes, schools and businesses, etc.
- Sections of the pipeline are installed along residential streets which would result in human environment (noise, dust, nuisance etc.) impacts during removal construction; and
- The preliminary screening cost estimate to remove and dispose of the majority of the existing NPS 20 pipeline is approximately $75 million as detailed in the response to BCUC IR 1.11.7. This compares to $3.1 million estimated cost to abandon the pipeline in place. There may be potential salvage value from recovery of the pipe steel during disposal; however, any salvage value would not likely offset the disposal costs, resulting in no net value to FEI.

Based on these considerations, FEI has selected abandonment of the NPS 20 Coquitlam Gate pipeline in place as the lowest cost, least overall impact end-of-life solution as detailed in Exhibit B-1, section 3.3.3. FEI will endeavor to identify, manage and mitigate potential environmental, public or stakeholder legacy issues. This will include any adverse effects from abandonment, resulting from pipe degradation after removal of cathodic protection (refer to the responses to CEC IRs 1.45.1, 1.45.7, 1.45.8, 1.45.9, 1.45.10, 1.45.11 and 1.45.14), which, however, will be mitigated by sectionalizing the pipeline, filling with a structural grout where warranted to prevent potential future collapse, and sealing open ends to prevent abandoned sections of pipe from acting as a water conduit and causing erosion.

Therefore, in the case of the NPS 20 pipeline, abandonment in place is proposed by FEI as an appropriate solution, and is the preferred alternative compared to pipeline abandonment through removal, as it can mitigate removal impacts through avoiding the significant disturbance to existing road, railway and utility crossings, natural areas, parks, environmentally sensitive areas and communities along the route alignment.

Notwithstanding the above, after the NPS 30 Coquitlam Gate IP pipeline is commissioned, removal and disposal of short sections of the NPS 20 pipeline will be required to facilitate the abandonment process. However, these locations will involve small scale excavations and be chosen where the NPS 20 pipeline has least depth of cover, is readily accessible and will minimize local construction impacts. The removal of further sections of pipeline is not considered feasible based on the site specific considerations previously outlined.

45.5 If yes, please identify and explain the site specific considerations and why they prevent removal after commissioning of the new pipeline.

Response:

Please refer to the response to CEC IR 1.45.4.

45.6 If not, is it possible to remove or remove sections of the pipeline once the new pipeline is commissioned?

Response:

Please refer to the response to CEC IR 1.45.4.

45.6.1 If yes, what considerations normally determine whether or not a pipeline should be removed, partially removed or abandoned in place? Please explain and quantify the economic considerations.

Response:

Please refer to the response to CEC IR 1.45.4.

45.6.2 If it is possible to remove sections of the pipeline after commissioning the new pipeline, what sections of the pipeline could be feasibly removed after commissioning?

Response:

Please refer to the response to CEC IR 1.45.4.

45.6.3 If it is not possible to remove some or all of the existing pipeline after commissioning of the new pipeline, please explain why not.

Response:

Please refer to the response to CEC IR 1.45.4.

45.6.4 Is there any potential salvage value from removing the pipeline?

Response:

Please refer to the response to CEC IR 1.45.4.

45.6.4.1 If yes, please provide quantification of the potential salvage value of the pipeline.

Response:

Please refer to the response to CEC IR 1.45.4.

45.7 Is it contrary to CSA Z662-11 to continue cathodic protection, or is that at FEI discretion?

Response:

FEI is committed to responsible abandonment of the pipeline. FEI has concluded that, after commissioning of the replacement NPS 30 pipeline, it has no further use for the NPS 20 pipeline as a carrier for pressurized gas or as a conduit or casing for pressurized gas or other facilities. Therefore, as it is at FEI's discretion to discontinue cathodic protection and maintenance schedules, and there is no reason for continuing cathodic protection or maintenance activities on the pipeline, these activities will cease after abandonment. CSA Z662, Clause 10.16.1 states:

> *"The decision to abandon a section of piping, in place or through removal, shall be made on the basis of an assessment that includes consideration of current and future land use and the potential for safety hazards and environmental damage to be created by ground subsidence, soil contamination, groundwater contamination, erosion, and the creation of water conduits."*

45.7.1 If it is at FEI's discretion, please explain why FEI is removing cathodic protection.

Response:

Please refer to the response to CEC IR 1.45.7.

45.8 Please provide a list of the potential issues surrounding the removal of cathodic protection, and whether or not these could apply in these circumstances.

Response:

Potential issues surrounding the removal of cathodic protection, which could occur in the case of the abandoned NPS 20 Coquitlam Gate IP pipeline, include:

- The abandoned pipeline will corrode at natural corrosion rates; however, as the pipeline coating will generally remain intact, only localized corrosion at coating holidays will take place. This could result in water ingress into the pipe causing the pipe to corrode internally.
- There is potential for loss of structural integrity where large areas of general corrosion (wall thinning) occur. This will be mitigated by filling the pipe with structural grout where warranted.

- The pipe could be subject to stray current corrosion and/or interfere with nearby CP systems on other utilities. This will be mitigated by sectioning the pipeline.

As a further consideration, the risk of CP interference with other pipelines or utilities is greater with an operating CP system than with no CP system. As CP will no longer be applied to the NPS 20 pipeline after abandonment, there is a potential risk of the abandoned pipeline acting as a low resistance path for CP currents intended for other pipelines or utilities. FEI will mitigate this by sectioning of the abandoned pipeline and disconnecting all connections to it.

45.8.1 Please confirm that there are no other operating pipelines in a common corridor with the abandoned pipeline which could be interfered with or have their CP electrically shielded as a consequence of the removal of the CP on the abandoned pipeline.

Response:

Please refer to the response to CEC IR 1.45.8.

45.9 Please confirm or otherwise explain that the abandoned pipelines will be subject to greater corrosion than is currently being experienced as a result of diminished maintenance, removal of cathodic protection, loss of internal pressure and increased potential for water ingress, etc.

Response:

It is expected that the abandoned pipeline will be subject to greater corrosion than is currently being experienced as a result of removal of cathodic protection, increased potential for water ingress, and unrepaired coating damage due to third party impacts.

Please refer also to the response to CEC IR 1.48.5.

45.10 Please identify all the factors that will contribute to internal and external corrosion of the abandoned pipeline.

Response:

The factors that contribute to external corrosion of the abandoned pipeline include:

- No cathodic protection: the abandoned pipeline will be subject to natural corrosion rates, which will differ along the length of the pipeline depending on soil type, coating condition, ground water presence and rate of movement, temperature, presence of microbiological organisms, and other possible contributors such as aeration of the soil surrounding the pipe.
- Stray current corrosion: the abandoned pipeline could be subject to stray current corrosion as it will act as a low resistance path for electrical currents in the earth from sources such as CP systems protecting other nearby utilities. To mitigate this risk, the abandoned pipeline will be sectioned into shorter lengths.
- Corrosion under disbonded coating: the corrosion that is currently causing leaks at girth welds underneath disbonded coating will continue.
- Third party damage: damage to the abandoned pipeline coating from third party impacts would result in exposed pipe metal which would be expected to accelerate the corrosion process.

The factors that contribute to internal corrosion of the abandoned pipeline include:

- Moisture or water: even though the abandoned pipeline will be purged, cleaned and sealed, through-wall external corrosion could enable water ingress into the pipeline, which would increase the likelihood of internal corrosion. Abandoned sections of pipe filled with a structural grout will have a reduced potential for water ingress and will have a high pH (alkaline), which would help to reduce internal corrosion rates.

45.11 Please explain how corrosion and/or any other factors negatively affecting the structural integrity of the pipeline can be expected to impact the abandoned pipeline over a 25 year, fifty year and 100 year period.

Response:

As the pipeline factory-applied coating will remain intact, it is expected that, over time, corrosion will manifest in the form of pitting or localized through-wall corrosion at coating holidays and areas of coating disbondment, as opposed to general corrosion over large areas resulting in pipe wall thinning and ultimately loss of structural integrity.

Furthermore, it is expected that internal corrosion, over time, will also result in through-wall corrosion at low elevation points with presence of internal moisture in given pipe segments.

As discussed in the response to CEC IR 1.45.4, the ultimate loss in structural integrity as a result of this corrosion will be mitigated by filling the abandoned pipe with a structural grout where warranted.

Given these factors and the associated uncertainty, FEI is unable to provide specific predictions on the future performance of the pipeline over the three time periods referenced.

45.12 Would FEI be liable in the event of a structural failure of an abandoned pipeline? Please explain why or why not.

Response:

Very generally speaking, if FEI was found to be at fault for a structural failure of the abandoned pipeline, FEI could be liable. However, FEI has selected abandonment of the NPS 20 Coquitlam Gate IP pipeline as the least impact end-of-life solution, and, in doing so, will identify, manage and mitigate the potential environmental, public or stakeholder legacy issues. Therefore, FEI does not foresee any significant adverse effects as a result of abandoning the pipeline in place.

45.13 Will the new pipeline likely be abandoned in place as well once it has come to the end of its service life? Please explain why or why not.

Response:

This is a difficult scenario to contemplate given the time frame. Nonetheless, the proposed pipeline would be decommissioned at the end of its service life in accordance with the regulatory requirements of the day. FEI anticipates the service life of the new pipeline to be at least 60 years.

45.14 To the extent that the field applied coating at the girth welds is causing unusual corrosion, will there be increased perforations occurring in these locations in the abandoned pipeline?

Response:

Confirmed. Further to this, FEI believes there is no consequential impact due to potentially increased through-wall perforations at girth welds for the abandoned pipeline.

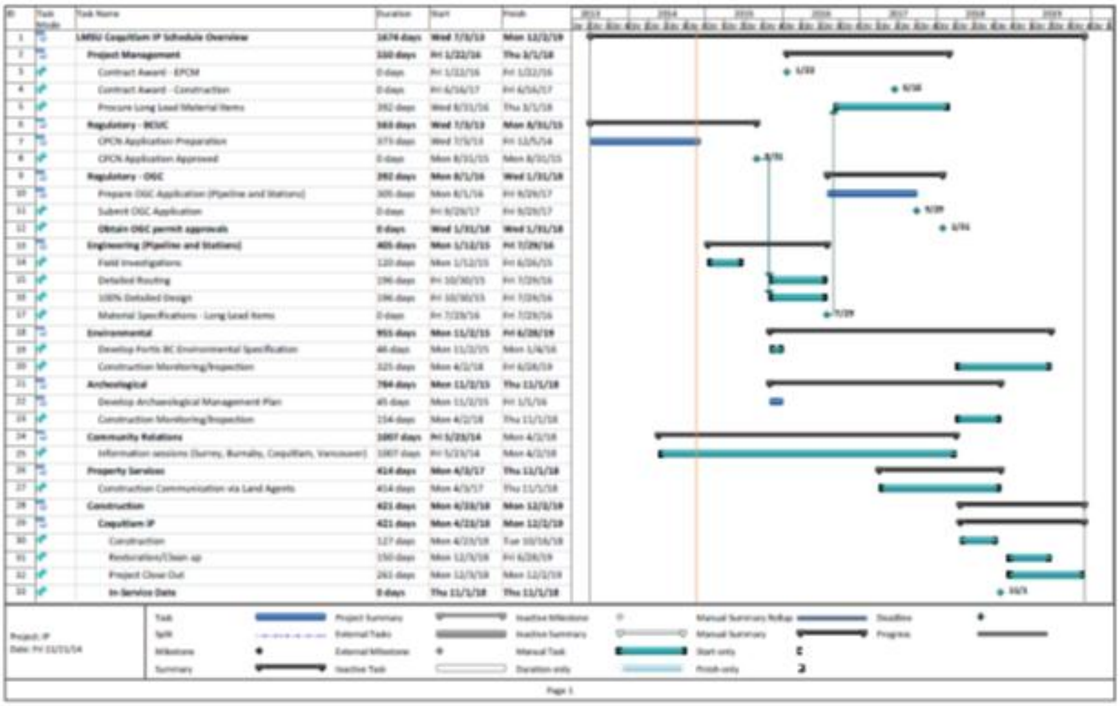
Please also refer to the response to CEC IR 1.45.1.

45.14.1 If yes, what is the impact of the potential increase in perforations at the girth welds?

Response:

Please refer to the response to CEC IR 1.45.14.

46.0 Reference: Exhibit B-1-1, Appendix A-20-1, Page 2 (unnumbered)



46.1 Does FEI still anticipate Commission approval by August 31, 2015?

<u>Response:</u>

The Company no longer anticipates Commission approval by August 31, 2015 given that Order G-1-15 contemplates more regulatory review process, yet to be determined. However, FEI respectfully requests Commission approval by December 2015 so that detailed routing and design can begin in early 2016 to enable procurement of long lead materials in late 2016. This will allow the Company to meet a 2018 in-service date for the Coquitlam Gate IP and Fraser Gate IP Projects.

In the event FEI receives Commission approval later than December 2015, the Projects' schedule would be re-evaluated. However, a CPCN approval beyond December 2015 could delay the planned 2018 in-service date by one year. This is due to the fact that the detailed engineering and design needs to be processed sufficiently to facilitate procurement of the long lead material items that are required onsite at the start of project construction. The construction window generally extends from the spring until the fall and generally does not extend into the winter because the operational risk is greater due to peak load demands on the system and because of increased construction costs associated with poor weather conditions.

If Commission approval was granted earlier than December 2015, then Project components such as detailed engineering and routing, which will not commence prior to Commission approval, could commence earlier.

46.2 Please explain how a delay in Commission approval would likely affect the project timelines.

Response:

Please refer to the response to CEC IR 1.46.1.

46.3 Are there any portions of the project that could be undertaken earlier or done more quickly if Commission approval was granted earlier or later than anticipated?

Response:

Please refer to the response to CEC IR 1.46.1.

46.3.1 If yes, please identify those portions that could be undertaken earlier and those portions which could be undertaken more quickly.

Response:

Please refer to the response to CEC IR 1.46.1.

46.4 Please confirm that that the Commission will be advised of any significant changes in the costs, routing, engineering or other aspects of the project that are identified prior to BCUC approval.

Response:

Confirmed.

47.0 Reference: Exhibit B-1, Pages 74 and 82

1. Open areas of roadways with no utility crossings have the least construction constraints and therefore the highest productivity;
2. Areas of roadway with less frequent utility crossings are the next level of construction productivity;
3. Areas where only water service connections need to be crossed are the next productive;
4. Areas where the gas pipeline must be pulled into an excavated trench under a high density of utility connections which cross over the trench and cannot be disconnected are the next productive; and
5. Trenchless construction is the least productive.

3.3.5.1.5 TRENCHLESS INSTALLATION

Sections of the Coquitlam IP pipeline will require installation requiring methods other than traditional open cut; three trenchless techniques have been identified for this requirement.

47.1 In what types of areas will trenchless construction be required?

Response:

Trenchless construction, as detailed in Exhibit B-1, section 3.3.3.5.1.5, will be used in a number of areas where it is not possible to excavate a trench to install the NPS 30 Coquitlam Gate IP pipeline, or it is necessary to minimize the surface impact from pipeline construction by avoiding typical trenched pipeline installation. Specific locations along the NPS 30 pipeline route where trenchless crossings are currently planned include:

- Class A water courses;
- Major road crossings (e.g. Trans-Canada Highway 1 at East 1st Avenue);
- Areas with large or sensitive third party buried infrastructure;
- Areas with high density of surface utilities; and
- Major intersections and accesses.

47.2 In how many sections of the Coquitlam IP pipeline does FEI anticipate using trenchless construction?

Response:

FEI anticipates horizontal directional drilling or microtunnelling trenchless construction techniques will be required in three locations of the Coquitlam Gate IP pipeline:

1. Clarke Road crossing at Como Lake Avenue;
2. Stoney Creek crossing in Burnaby; and
3. Highway 1 crossing at East 1st Avenue.

There will also likely be a number of shorter bored crossings typically at major traffic intersections.

Please also refer to Exhibit B-1-1, Appendix A-17 and Exhibit B-1, section 3.3.5.1.5 for further details.

47.3 Will FEI select one preferred method (of the three techniques) or use a mix of trenchless techniques depending on circumstances?

Response:

It is unlikely FEI will select one preferred trenchless method. Instead, where trenchless construction is required, FEI will specify the trenchless locations, extent of the trenchless crossing and other fundamental design requirements, including the results of field investigations, in the Project construction tender documentation. Then, based on the outcome of the tender process, FEI will engage a pipeline contractor with the necessary proven skills, resources, equipment and expertise to implement each trenchless crossing using the most appropriate trenchless technique that best meets the design specifications, mitigates the risk presented by varying or unknown sub-surface conditions and is cost-effective. The final determination of the most appropriate method will be site specific for each crossing location and may involve different trenchless techniques for different locations.

47.4 If FEI will use one technique, has FEI selected a preferred technique?

Response:

Please refer to the response to CEC IR 1.47.3.

47.4.1 If yes, please identify the technique and why it was chosen.

Response:

Please refer to the response to CEC IR 1.47.3.

48.0 Reference: Exhibit B-1, Page 80

> As a result of the feedback from the City, FEI, in conjunction with the City of Burnaby and in consultation with other stakeholders such as Translink, B.C. Hydro and MoTI, will conduct further analysis to determine if a route option along Lougheed Highway in Section 5 and 6 is feasible. It is anticipated that this analysis will be completed by early 2015. If the analysis shows that a route option along Lougheed Highway is technical feasible, constructible, that traffic issues can be managed with reasonable efforts and that the route option scoring and cost is comparable to the current preferred route alignment options, FEI will submit a revised route evaluation for the sections of route corridor through Burnaby to the BCUC for consideration.

48.1 Has FEI completed the additional analysis to determine feasibility of the route option along Lougheed Hwy yet?

Response:

Please refer to the responses to BCUC IRs 1.18.1 and 1.18.2.

48.1.1 If yes, what were the results of the analysis?

Response:

Please refer to the response to BCUC IR 1.18.2.

48.1.2 If no, when does FEI expect the analysis to be complete?

Response:

Please refer to the response to BCUC IR 1.18.2.

48.1.3 Would a option along the Lougheed Hwy likely be less costly than the alternative currently selected?

Response:

Please refer to the response to BCUC IR 1.18.2.

48.1.3.1 If yes, please provide an approximate of the % savings that may accrue from this option.

Response:

Please refer to the response to BCUC IR 1.18.2.

49.0 Reference: Exhibit B-1, Pages 81 and 92

> **3.3.5 Construction, Installation and Commissioning**
>
> It is intended that the Coquitlam Gate IP pipeline will be constructed by one pipeline construction contractor beginning in the summer season of 2018. The Project is expected to be completed with five separate construction crews due to congestion and proximity of obstacles impeding the work zones as a result of working in a built up urban area. Final cleanup will be completed as the construction progresses.
>
> ***3.3.7.2 Construction Services***
>
> FEI will issue an Expression of Interest to identify potential prime construction contractors and pre-qualify selected contractors prior to the release of the tender documents. The construction will be subject to a competitive tender. At the close of the procurement process, FEI will select the final successful Contractor based on capability, safety, schedule and cost. FEI will select the bid that provides the best overall value.

49.1 When does FEI anticipate receiving Expressions of Interest?

Response:

FEI sent out Expressions of Interest to potential interested pipeline contractors in Q4 2014. FEI has received responses and is currently evaluating them for suitability.

49.2 Does FEI consider prior experience with a particular contractor a relevant criterion?

Response:

Prior experience with a particular contractor would be a relevant consideration, as long as the other criteria are also met. However, FEI has not had previous experience with a contractor on a similar large-scale urban pipeline within the Metro Vancouver region, so the Company does not expect this consideration will be a significant determining factor in the evaluation of contractors.

49.2.1 Please explain why or why not.

Response:

Please refer to the response to CEC IR 1.49.2.

49.3 Has FEI ever used multiple prime contractors to complete a single large project? Please explain why or why not.

Response:

Confirmed. FEI has used multiple prime contractors to complete a single large project in the past. To determine whether one or more prime contractors are needed, FEI considers the project's size and complexity, project resourcing and construction management requirements in order to ensure safety, environmental, quality, cost and schedule project objectives are met.

49.3.1 If yes, what were the noted advantages and disadvantages? Please explain.

Response:

Many of the items as listed in the response to CEC IR 1.49.3.2 are applicable to past large projects that FEI has executed.

49.3.2 What are the advantages and disadvantages of using a single contractor versus multiple prime contractors? Please explain.

Response:

The advantages of using multiple prime contractors for a single large project may include:

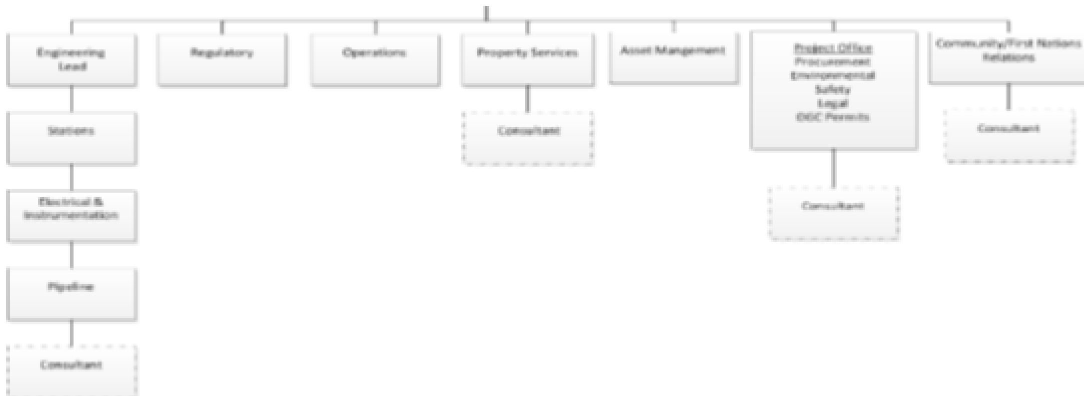
- Lower construction costs as there is an increased competition among bidders;

- Fast-tracking capabilities as the owner has more control over the project schedule and individual issuing of tenders;
- Higher quality of work as more specialty contractors are attracted to the tenders issued; and
- More detailed plans performed in the early design stages of the Project to facilitate discussions with multiple contractors.

The disadvantages of using multiple prime contractors for a single large project may include:

- Increased coordination and administrative expenses on behalf of the owner to differentiate responsibilities and avoid the potential of work scope omission or duplication;
- Overall Project performance can be weakened as responsibilities are distributed amongst various contractors;
- Increased Project costs as there is the potential for numerous claims;
- Change orders and delays as no contractual relationships exist among the contractors; and
- Increased level of scheduling for the owner with various different contractors with the potential for one contractor to impact another contractor’s schedule.

50.0 Reference: Exhibit B-1, Page 91



50.1 Has FEI selected the consultants for Engineering, Property Services and Community Relations yet?

<u>Response:</u>

FEI has selected a consultant for Engineering but not for Property Services or Community Relations.

50.1.1 If yes, please identify the Consultants selected.

<u>Response:</u>

The Engineering consultant selected is WorleyParsons Canada Service Ltd.

51.0 Reference: Exhibit B-1, Page 100

> 3.4.1.4.2 ESCALATION
>
> An escalation rate of 4.5 percent per annum is used based on the ten year average escalation rates from Statistics Canada for industrial construction and line pipe from 2002 to 2012.

51.1 Please provide the dataset for the escalation rates from 2002 to 2012.

Response:

Please refer to the response to BCUC IR 1.49.1 for the dataset for escalation rates from 2002 to 2014.

51.2 What was the escalation rate for 2013?

Response:

Please refer to the response to BCUC IR 1.49.1 for the escalation rate for 2013.

51.3 Why was the escalation rate for 2013 not included?

Response:

The data set in Cansim from Statistics Canada was terminated in 2013 so that a full year's data was not available. Based on the partial year of information that was available, the ten year 2003 -2013 average inflation rate was approximately 4.2%. It is FEI's preference to use the complete 10 year average and since the two results were close, FEI decided it was reasonable to use the 4.5 percent from 2002-2012.

51.4 Why should a ten year average be used?

Response:

Please refer to the response to BCUC IR 1.49.3.

52.0 Exhibit B-1, Page 102

> One activity within the FEI IMP is Seismic Hazard Management. The objective of this activity is to maintain pressure integrity such that failure of identified assets will not pose a hazard to the public immediately following ground displacements during an earthquake with a 1:2475 return period. FEI undertakes periodic reviews of existing assets. These reviews are completed at a level of detail appropriate to the assessed hazard.
>
> Given an identified seismic vulnerability on a segment of the Fraser Gate IP pipeline (i.e. vulnerable to failure due to less than 1:2475 year seismic induced ground movement), FEI engaged DGHC in 2012 to produce a Site Specific summary report to capture the level of pipeline vulnerability and to recommend necessary follow-on study or mitigation measures for the Fraser Gate IP pipeline. This Summary of Site-Specific Seismic Vulnerability Assessment of the Fraser Gate IP pipeline report, dated Feb 2013, is attached as Appendix A-4.

52.1 Please provide a brief list of the other activities that are included in the FEI IMP.

Response:

The following is a list of all activities included in the FEI Integrity Management Program (IMP):

IMP Hazard or Grouping	Activity
Third Party Damage	Depth of Cover Management
	DP Service Hazard Management
	Right of Way Management
	Pipeline Identification
	Pipeline Patrol
	IMP Public Safety Awareness
	Security Management
	Vegetation Management
Natural Hazards	Geotechnical and Hydrotechnical Hazard Management
	Seismic Hazard Management
Pipe Condition	Cathodic Protection
	In-Line-Inspection
	Pipe and Coating Condition Reporting
	Stress Corrosion Cracking Management
Material Defects & Equipment Failures	Gas Quality Management
	Maintenance Programs
	Materials Quality Assurance

IMP Hazard or Grouping	Activity
Construction & Operations	Field Quality
	Pressure Management
Core Activities	Asset Design
	Capital Management
	Competency Management
	Corrective Work Management
	Records Management
	Standards Management
Consequence Reduction	Class Location Management
	Odorization Management
	Leak Survey
Continual Improvement	IMP Review
	IMP Corrective Action / Continuous Improvement Management
	Learning From Incidents

52.2 How often is the periodic review FEI undertakes of existing assets?

Response:

To assess when periodic review of existing assets may be required, FEI monitors for significant changes to data, criteria or the methodology to support seismic analysis. These factors may change significantly on an infrequent basis.

As an example, FEI conducted periodic reviews in 1994 and 2010. The assessment in 2010 was driven primarily as a result of changes to the definition of the seismic hazard in British Columbia (published by the Geological Survey of Canada); however, it also leveraged subsequent development in analysis tools and methodology.

52.3 How many other pipelines and/or segments are identified as being at risk in the FEI system?

Response:

Please refer to the response to CEC IR 1.4.3.1.

52.4 Does FEI prioritize the identified seismic vulnerabilities on its system?

Response:

FEI addresses seismic vulnerabilities on a planned basis, and considers both technical and resource factors in planning and scheduling mitigation.

Factors considered in selecting a schedule include:

- Estimated probability of failure;
- Estimated consequences of failure (safety, economic);
- Ease or difficulty of determining or implementing a solution to mitigate the risk;
- Ease or difficulty of repair, including duration of repair, in the event of a seismic-related failure; and
- Financial considerations, including impact to other identified system work.

The schedule essentially translates into a prioritization for implementation of mitigation projects.

52.5 If so, please identify where the Fraser Gate IP was placed by priority level.

Response:

In accordance with the considerations identified in response to CEC IR 1.52.4, FEI has scheduled the Fraser Gate IP mitigation concurrent with the construction of the proposed NPS 30 Coquitlam Gate IP pipeline due to the following factors:

- Identified pipeline vulnerability to a 1:2475 seismic event, as further discussed in Section 4.1.2.1 of the Application (Exhibit B-1);
- Significant consequences of failure (both safety-related and economic-related), as further discussed in Sections 4.1.2.2 and 4.1.2.3 of the Application; and
- An opportunity for improved constructability of a pipe replacement, as outlined in response to CEC IR 1.65.1.3.

52.6 Please provide any priority matrices that FEI may have developed with respect to managing seismic risk in its system.

Response:

FEI has not developed priority matrices with respect to managing seismic risk in its system. Rather, as relatively few sites that require mitigation have been identified through regional studies and assessments, FEI considers the factors described in the response to CEC IR 1.52.4 when establishing a schedule for seismic-related mitigation projects.

52.7 When was the Fraser Gate IP pipeline last included in the periodic review of assets?

Response:

Prior to a periodic review of FEI pipelines in 2010, the Fraser Gate IP pipeline was last included in a 1994 review.

52.7.1 If Fraser Gate has been reviewed in the past, when was the seismic vulnerability first identified?

Response:

The seismic vulnerability of the Fraser Gate IP pipeline was identified in a 1994 regional assessment. However, a subsequent site specific assessment was undertaken for the pipeline segment to confirm the degree of vulnerability. Using data and methods at the time, the conclusion was that no mitigation was required for the NPS 30 Fraser Gate IP pipeline to meet FEI's then seismic criteria. Please refer to response to BCOAPO IR 1.4.1 for a copy of this study dated January 20, 1997.

The current vulnerability was identified in a 2010 regional-level study; however, the need for the proposed Fraser Gate IP Project was confirmed through the Site-Specific Seismic Vulnerability Assessment of the Fraser Gate IP, dated February 2013, and included as Appendix A-4 (Exhibit B-1-1).

52.7.2 If the Fraser Gate seismic vulnerability was identified prior to 2012, why has it not been addressed earlier?

Response:

Please refer to the response to CEC IR 1.52.7.1.

52.8 Please confirm or otherwise explain that the OCG has not identified the Fraser Gate pipeline as requiring seismic upgrading.

Response:

Confirmed.

53.0 Exhibit B-1, Page 103

> In addition to the safety concern noted above, the potential consequence of large-scale service impacts to up to 171,000 customers and the economic loss resulting from failure of the Fraser Gate IP pipeline due to a seismic event is an additional driver for this Project.

53.1 Please confirm or otherwise clarify that the potential consequence and impact up to 171,000 customers would be completely mitigated if the Coquitlam Gate IP is replaced with the 30 pipeline operating at 2070 kPa.

<u>Response:</u>

Please refer to the response to CEC IR 1.5.1 for clarification on conditions in which the NPS 30 IP pipeline would completely mitigate impact to the 171,000 customers.

54.0 Reference: Exhibit B-1, page 105 and Exhibit B-1-1, Appendix A4, Page 1

> *"The allowable compression strain for pressure integrity is 1.8% based upon the relationship between the ratio of wall thickness to pipe diameter in PRCI guidelines (Honegger and Nyman, 2004). Based upon these strain limits, the horizontal displacement capacity is approximately 0.5 m, which is greater than the 475-year displacement estimate but well below the 2,475-year displacement estimate of 1.6 m."* (See Appendix A-4, page 3)

> Based upon the findings from a regional vulnerability assessment conducted in 2010 (DGHC, 2010), FortisBC Energy (Fortis) identified fifteen locations for site-specific assessment of the likely seismic ground displacement hazard and the pipeline response to that displacement. The assessments of seismic ground displacement hazard were performed by geotechnical consultants contracted directly by Fortis. Ground displacement estimates for ground shaking with mean return periods of 475-years and 2,475-years. The findings from these assessments were documented in a single report to Fortis (DGHC, 2012).

54.1 Please explain why the ground displacement estimates were conducted for 475 years and 2,475 years as opposed to other periods.

<u>Response:</u>

The 1:2475 seismic level was evaluated to enable an assessment of pipeline compliance with FEI's seismic performance requirement. The rationale for this period is contained in FEI's design standard DES 09-02, included as Appendix A-28 (Exhibit B-1-1).

The 1:475 seismic level was evaluated to provide an additional vantage point from which to assess relative vulnerability between sites, as well as to enable comparison with prior seismic assessment practices for FEI pipelines.

55.0 Exhibit B-1, page 107 and Exhibit B-1-1, Appendix A-4, Page 3

> To achieve the objectives and requirements outlined above, FEI considered two alternatives, and selected the upgrade of a 500 metre segment of NPS 30 pipe, installed on the south side of East Kent Avenue as the preferred alternative, based on an evaluation of both financial and non-financial factors. The following alternatives were considered to be the only available alternatives, and are discussed below:
>
> - Alternative 1 - Do nothing; and
> - Alternative 2 – Existing pipeline abandonment, and upgraded replacement. Replace a segment of NPS 30 pipeline from Fraser Gate to the corner of East Kent Avenue & Elliott Street with a higher grade of steel and thicker pipe wall to mitigate the seismic risk. This is the only alternative that will provide the required seismic resistance.

> **2.3 Recommended Action at Location LM-7**
>
> Two options exist for improving pipeline response. The existing pipeline could be replaced with a pipeline having a higher grade of steel and a thicker pipe wall. Replacing the pipeline in the existing right-of-way would require installation of a temporary by-pass pipeline. An alternate option is to avoid the hazard by relocating the pipeline on East Kent Avenue South to East Kent Avenue North.

55.1 Why did FEI not address the alternative of avoiding the hazard by relocating the pipeline to East Kent Avenue North?

Response:

As discussed in Exhibit B-1 section 4.3.4, FEI did address the alternative of avoiding the hazard by relocating the pipeline to East Kent Avenue North.

55.2 Please provide any economic analysis that FEI undertook with respect to relocating the pipeline.

Response:

Please refer to the response to CEC IR 1.56.1.

55.3 Are there any alternatives in existence for addressing pipeline vulnerability other than improving pipeline response, such as ground improvement or pipeline protection?

Response:

Please refer to the response to BCUC IR 1.33.1.2.

55.4 If yes, please identify these options and explain whether or not they were considered.

Response:

Please refer to the response to BCUC IR 1.33.1.2.

55.4.1 If alternative options exist and were not considered, please explain why not.

Response:

FEI believes it has considered all feasible alternatives .

Please also refer to Exhibit B-1, section 4.2, and the response to BCUC IR 1.33.1.2.

56.0 Exhibit B-1, Pages 109 and 110

> FEI evaluated the incremental cost of service, cash flow and rate impacts associated with Alternative 2 – Route Option 1 over a 60 year period. The 60 year time horizon was chosen to be consistent with the assumed useful life of the assets. The incremental cost of service estimates are based on FEI's currently approved capital structure, cost of capital and tax treatment.

Table 4-2: Fraser Gate IP Project Financial Analysis

	Alternative 2 – Route Option 1 – East Kent Ave South
Estimate Accuracy	Class 3
Total Direct Capital Cost excl. AFUDC (2014 $millions)	14.855
Total Direct Capital Cost excl. AFUDC (As-spent ($millions)	17.231
AFUDC (as spent ($millions)	0.876
Total As-spent ($millions)	18.107
Annual Gross O&M (2014 $millions)	0.001
Levelized Rate Impact $ / GJ – 60 Yr.	0.007
PV Incremental Cost of Service – 60 Yr. ($millions)	21.654

56.1 Did FEI evaluate the cost of service, cash flow and rate impacts from the other route alternatives?

Response:

A Class 5 Capital Cost Analysis and the financial analysis to determine incremental cost of service and rate impact had been done for the East Kent Ave North route option. FEI did not conduct a cost of service, cash flow and rate impact evaluation of the route option for Jellicoe Street and Marine Drive as the capital cost (2014$) was twice the cost of the preferred route option.

The following provides the comparable values as in Table 4-2 for the East Kent Ave North route option compared to FEI's preferred Alternative and route option.

	Alternative 2 Route Option 1 East Kent Ave South	Alternative 2 Route Option 2 East Kent Ave North
Estimate Accuracy	AACE Class 3	Class 5
Total Direct Capital Cost excl. AFUDC (2014 $millions	14.855	16.713
Total Direct Capital Cost excl. AFUDC (As-spent $millions)	17.231	19.279
AFUDC	0.876	1.135
Total As-spent ($millions)	18.107	20.414
Annual Gross O&M (2014 $millions)	0.001	0.001
Levelized Rate Impact $ / GJ – 60 Yr.	0.007	0.008
PV Incremental Cost of Service – 60 Yr. ($millions)	21.654	24.440

56.1.1 If no, please explain why not.

Response:

Please refer to the response to CEC IR 1.56.1.

56.1.2 If yes, please provide the results of the evaluation in the same form as Table 4-2.

Response:

Please refer to the response to CEC IR 1.56.1.

57.0 Exhibit B-1, Page 113

4.3.3.2.2 FRASER GATE STATION

The existing Fraser Gate station was previously upgraded in 1997 to mitigate the seismic vulnerabilities of the station, but the pipeline along East Kent Avenue was not identified as requiring mitigation at that time. Subsequent seismic investigations in the area determined that the existing Fraser Gate IP pipeline is vulnerable to a 1:2475 year seismic event.

57.1 Did FEI not conduct seismic investigations of the area at the time of the Fraser Station upgrade, or has new evidence been discovered in the latter investigations? Please explain.

Response:

Please refer to the response to CEC IR 1.52.7.1 for a description of seismic investigations undertaken.

58.0 Exhibit B-1, Page 114

> **4.3.3.3.2 PIPE SPECIFICATION**
>
> Please refer to section 3.3.3.3.2 for additional information on the pipe selection methodology.
>
> Based on the preliminary design that was completed, the selected wall thickness and steel grade are 11.1 mm and Grade 483 respectively. As this replacement is required to mitigate seismic vulnerabilities of the existing pipeline, the steel grade was increased to a higher grade than what is required for hoop stress. During detailed design, further seismic and stress analysis will be completed to validate the pipe wall thickness and grade selection.

58.1 What is the grade that is required for hoop stress?

Response:

Grade 241 is required for hoop stress based on the wall thickness selected; however CSA Z662-11 Section 4.2.4 requires that additional loadings, including those related to seismic-related earth movements, also be considered during design. Please refer to Exhibit B-1-2, Confidential Appendix A-12.

59.0 Exhibit B-1, Page 115

> 4.3.3.3.5 IN-LINE INSPECTION
>
> The existing Fraser Gate IP pipeline is not designed to accommodate in line inspections (ILI). This project will replace a small portion of the NPS 30 Fraser Gate IP pipeline which will not result in a piggable pipeline. However, the section of new pipeline that will be installed will be designed to accommodate ILI should it become feasible at some point in the future.

59.1 What circumstances would result in ILI becoming feasible at some point in the future?

<u>Response:</u>

Unlike the proposed NPS 30 Coquitlam Gate IP pipeline, the existing NPS 30 Fraser Gate IP pipeline was not designed to be in-line inspected.

Currently, no ILI vendors are offering conventional free-swimming NPS 30 ILI tools to inspect gas pipelines operating at 1200 kPa. If in the future these tools were to become available, then any existing reduced diameter mainline valves, bore restricting fittings and tight radius elbows would have to be removed to allow tool passage. It is unlikely that full ILI data would be collected for the entire line due to tool speed excursions, and the risk of lodging the tool in the pipeline due to unknown inside diameter restrictions, requiring tool cutout, would be high.

59.2 What is the likelihood of such events occurring within the expected life of the pipeline?

<u>Response:</u>

Although FEI has no plans to run in-line inspection tools in the NPS 30 Fraser Gate IP pipeline at this time, it is considered possible that selected segments of the pipeline may be in-line inspected within the expected life of the pipeline.

FEI will continue to assess ILI technologies as they become available to see if they are compatible with this pipeline.

59.3 What, if any, is the approximate incremental cost of designing the section to accommodate ILI?

Response:

To enable ILI, the pipeline design will include bends with a minimum radius of three times the pipe diameter, which can accommodate recently available ILI technology.

Please refer to the response to BCUC IR 1.14.2 regarding the incremental cost to include ILI capability in this way.

60.0 Exhibit B-1, Pages 115 to 116

> **Cathodic Protection**
>
> Cathodic protection of the existing NPS 30 Fraser Gate IP pipeline is supplied via an impressed current cathodic protection (CP) system, comprising rectifiers and deep anode beds. These are located at No 7 Road and Vulcan Way in Richmond. The impressed current system has been applying CP to the pipeline since its installation. Replacement anode beds were most recently installed in 1984. This impressed current system provides protection to the NPS 30 Fraser Gate IP pipeline from Fraser Gate station to East 37th Avenue and Nanaimo Street. It is expected that
>
> the existing CP system could be used to provide protection to the new Fraser Gate IP pipeline; however this will be confirmed during detailed design.

60.1 What factors would limit the viability of the existing CP system to provide protection to the new Fraser Gate IP pipeline?

Response:

As this Project is simply replacing a section of the pipeline, FEI has not identified any factors that would limit the viability of the existing CP system to provide protection to the new Fraser Gate IP pipeline.

60.2 Please provide an order of magnitude estimation of the costs associated with having to make alternative arrangements for cathodic protection.

Response:

FEI does not expect that alternate arrangements for CP will be required. A new anode bed, if required, would typically be expected to cost approximately $50,000. However, the actual cost would depend on site specific requirements.

Please also refer to the response to CEC IR 1.60.1.

60.3 Please confirm that the estimated cost analysis incorporates the possibility that cathodic protection is not viable from the existing source.

<u>Response:</u>

The estimated cost analysis does not incorporate the possibility that utilization of the existing CP system would not be viable.

Please also refer to the response to CEC IR 1.60.1.

61.0 Exhibit B-1, Page 117

14 4.3.3.7.1 ABANDONMENT PROCESS
15 The existing NPS 30 IP pipeline will be abandoned in place once the new pipeline is in service.
16 See section 3.3.3.8 for additional information regarding the abandonment process.

61.1 Did FEI consider removing all or portions of the pipeline?

Response:

FEI has selected abandonment in place as the optimum end-of-life solution for the NPS 20 Coquitlam Gate IP pipeline, and the considerations informing this decision are presented in the response to CEC IR 1.45.4. The NPS 20 Coquitlam Gate IP pipeline is significantly longer in length than the NPS 30 Fraser Gate IP Project; however, the same approach applies to the NPS 30 Fraser Gate IP pipeline in terms of selecting the appropriate abandonment strategy which is based on various factors including site specific considerations.

The Fraser Gate IP pipeline cannot be decommissioned, or removed, until the NPS 30 Coquitlam Gate IP replacement pipeline is installed and commissioned. Notwithstanding that the existing NPS 30 and proposed replacement NPS 30 Fraser Gate IP pipeline segments are located within the same roadway, it is not possible to construct the new pipe and remove the existing pipe concurrently. The route alignment for the proposed replacement NPS 30 Fraser Gate IP pipeline is located such that construction staging will minimize access restriction impacts to the business served by East Kent Avenue South. The position of the existing NPS 30 Fraser Gate IP pipeline, and the complexities of removing any deeper sections, would involve construction excavation which would completely restrict access along East Kent South for a period of time while the abandonment and removal construction progressed. The business served by East Kent South requires unrestricted daily access maintained, with only short traffic flow interruptions tolerated. Furthermore, the removal of the existing NPS 30 Fraser Gate IP pipeline would not be cost effective, primarily due to challenging sub-surface conditions, including a high water table. FEI has also selected abandonment of the NPS 30 Fraser Gate IP pipe section in place as the overall least impact end-of-life solution and in doing so will identify, manage and mitigate the potential environmental, public or stakeholder legacy issues, in a similar fashion as outlined for the NPS 20 Coquitlam Gate IP pipeline.

61.1.1 If not, please explain why or why not.

Response:

Please refer to the response to CEC IR 1.61.1.

61.1.2 If yes, please explain why FEI opted to abandon the pipeline in place.

Response:

Please refer to the response to CEC IR 1.61.1.

62.0 Exhibit B-1, Page 122

> **Land Ownership and Use**
>
> Route Option 1 would involve temporary construction through a municipal park and privately owned land. Pipeline access rights would be required through these areas which would limit future development along the pipeline route, resulting in a potentially high impact to land ownership and use. Route Option 2 would require the temporary conversion of an existing recreational green space into roadway to allow for access to homes to be maintained. Route Option 3 would be wholly constructed within roadway, and have a low impact on land ownership and use. Route Option 2 and 3, compared to Option 1, would involve installation of the pipeline primarily within municipal roadway and would have less impacts in terms of land ownership and land use. However, Route Option 2 would temporarily impact on existing recreational green space on East Kent Avenue North. This would have a moderate short term impact on land use.
>
> - Route Option 1: high impact, poor route choice (2)
> - Route Option 2: moderate impact, good route choice (3)
> - Route Option 3: low impact, better route choice (4)

62.1 What are the potential costs associated with acquiring pipeline access rights? Please quantify where possible or provide on an order of magnitude basis where not estimated.

Response:

As outlined in the response to BCUC IR 1.31.4, FEI has revisited its prior understanding of the specific area of seismic vulnerability related to the Fraser Gate IP pipeline replacement. As a result, the length of seismically vulnerable pipeline which will be replaced may be reduced to a section from the outlet of Fraser Gate station to a point where the existing NPS 30 IP pipeline turns north to cross underneath the rail lines. This would significantly reduce the potential of construction impacting Gladstone Park as described Exhibit B-1, section 4.3.4.6.1. Nonetheless, should private lands be required, and provided the landowner is willing to enter into good faith negotiations regarding the acquisition of a pipeline right of way, the general costs associated with acquiring these rights can be characterized as follows:

1. Compensation payable to the landowner for the land rights. In most cases, an independent market appraisal is commissioned to establish values, based on market transaction of similar properties. Compensation payable to the landowner is size and location-dependent.
2. Professional fees payable to appraisers, surveyors, environmental and/or archeological specialists. The cost to prepare a formal fair market real estate appraisal ranges from $5-15 thousand, based on the specific attributes of the subject parcel. Costs for survey, likewise, are in the $5-15 thousand range, and are also dependent on the specific

attributes of the subject property. Should the land contain environmental features, such as a stream, or archeological features, then costs to research, understand and manage these features will also be incurred. It is difficult to estimate these costs as an average as the fees will depend on the complexity of the specific issue, and not every property will attract these costs.

3. Legal fees payable for documentation and conveyancing assistance. Depending on the nature of the transaction, these can range from a low of $1,500 up to several tens of thousands if the parties are not able to negotiate a reasonable agreement and acquisition becomes a taking by way of partial expropriation. In that extreme, FEI would be obligated to pay the landowner's legal fees.

4. Land agent costs to assist in the acquisition. If external resources are required, expenses to retain a land agent will add to the cost of the land acquisition. In most cases land agents charge on an hourly basis with rates ranging from $75-150. Again, depending on the complexity of the acquisition, the range could be from a low of $1,500 to a high of ten thousand or more.

5. Broker's fees payable if the subject parcel is actively marketed for sale or lease. Broker's fees range from 1.5% to 7% of land value, depending on the value and type of land being marketed.

62.2 Please confirm or otherwise explain that the cost estimate accounts for the acquisition of pipeline access rights.

Response:

FEI does not anticipate there to be costs associated with the acquisition of pipeline access rights. It was anticipated that with the approval of this Application, and pursuant to the terms of the existing City of Vancouver Operating Agreement, FEI is granted permission to construct its infrastructure in streets, parks and other public places on the approval of the City Engineer.

63.0 Exhibit B-1, Pages 125 and 126

Natural Hazards

The detailed design and final geotechnical analysis have not yet been completed; preliminary engineering indicates that all three route options will meet the Company's geotechnical and seismic standard requirements. Route Option 1 would be located within the seismic ground displacement zone and would meet FEI's seismic criteria of maintaining pressure integrity during a 1:2475 seismic event. Route Options 2 and 3 would be located outside of the ground displacement zone for the majority of the pipeline route. A small portion of both pipeline route options would be within the ground displacement zone at the exit of Fraser Gate station, and both route options would meet FEI's seismic criteria at this location.

half as long as Route Option 3. A preliminary screening estimate was completed for Route Option 2 which provided a cost estimate approximately 12 percent higher than Route Option 1. This is primarily due to the construction challenges associated with the non-standard trenchless construction and high density of existing buried utilities that would have to be relocated to accommodate pipe installation, and construction risks associated with long trenchless pipeline installations. The preliminary screening estimate for Route Option 3 provided a cost estimate approximately 113 percent higher than Route Option 1. Route Option 3 is the most expensive route option as it is over twice as long as Route Options 1 and 2 resulting in the additional construction costs.

4.3.4.7 Selected Preferred Route Option

The relative impact scoring of these route options in Table 4-4 reflects the impacts and considerations outlined in the previous sections. The total scores for Route Option 1, 2 and 3 are 335, 270 and 295 respectively.

63.1 To the extent that Options 2 and 3 are located outside the area of seismic concern, are the pipeline specifications reduced for portions those portions of the pipeline or do the same specifications apply as those in Option 1? Please explain.

<u>Response:</u>

Options 2 and 3, due to their respective locations, would have different design considerations and possibly different pipe specification requirements. This could result in the selection of a lesser pipe steel grade but maintain the same wall thickness. However, this would have to be confirmed through further detailed engineering analysis.

63.2 What is the approximate accuracy range of a 'preliminary screening estimate'?

Response:

The preliminary screening estimate is developed to an AACE Class 5 level of project definition with an associated approximate accuracy range -50% to +100%.

64.0 Exhibit B-1, Page 128

4.3.5 Construction, Installation and Commissioning

It is intended that the Fraser Gate IP pipeline will be constructed with the Coquitlam Gate IP Project by one pipeline construction contractor beginning in the summer of 2018. Final cleanup will be completed as the construction progresses.

64.1 Did FEI consider using a separate contractor for the Fraser Gate project? Please explain why or why not?

Response:

This response also addresses CEC IRs 1.64.2, 1.64.2.1 and 1.64.2.2.

FEI has not yet considered using a separate contractor because of various commonalities between the Coquitlam Gate IP and Fraser Gate IP Projects in terms of planning, engineering, materials, schedule, and pipeline construction. For these reasons, FEI is proposing a common contractor and that both Projects be executed in parallel to a common schedule. By using the same contractor for both Projects and by executing the Projects in parallel, FEI believes there to be potential cost benefits resulting from overall project efficiencies and economies of scale and has prepared the Projects' cost estimates on that basis.

For example, FEI anticipates that execution costs will be minimized over the Projects' lifecycle compared to executing each Project on a standalone basis. In addition, there could also be reduced mobilization costs, costs associated with personnel training and familiarization with FEI standards, procedures, and local regulations and requirements etc., and reduced costs associated with establishing relationships with local municipalities, etc. Given the factors involved, and the intangible nature of some of the potential cost benefits, the magnitude of such savings would be difficult to estimate with any level of certainty.

Please also refer to the response to CEC IR 1.3.2.

64.2 Does FEI anticipate savings from using the same contractor?

Response:

Please refer to the response to CEC IR 1.64.1.

64.2.1 If yes, please quantify the savings that FEI anticipates.

Response:

Please refer to the response to CEC IR 1.64.1.

64.2.2 If not, please explain why not.

Response:

Please refer to the response to CEC IR 1.64.1.

65.0 Exhibit B-1, Page 131

Table 4-5: Fraser Gate IP Project Schedule Milestones

Activity	Date
Conceptual Development	Completed.
CPCN Preparation	July 2013 – Dec 2014
CPCN Filing	Dec. 2014
CPCN Approval	Q3. 2015
Start of Detailed Engineering, materials specification and contract development	Oct. 2015
Materials Tendering and Orders Placed	Aug. 2016
Submit OGC Application	Sept. 2017
OGC Pipeline Approval	Jan. 2018
Award Contractor	June 2017
Materials Delivery	March 2018
Construction Start	July 2018
In Service	Nov. 2018
Restoration	June 2019

65.1 Is FEI able to generate savings such as reduced materials costs by coordinating construction with the Coquitlam Gate IP project?

Response:

FEI anticipates that savings will be achieved over the Projects' life cycle compared to executing each Project on a standalone basis, by leveraging economies of scale in a number of areas including materials procurement. For example, if the NPS 30 pipeline required for the Fraser Gate IP and Coquitlam Gate IP Projects necessitates the manufacture (a pipe mill run) of new pipe, then placing a unified order will realise manufacturing efficiencies and therefore potential overall procurement savings. The same potential benefit would also apply to the procurement of induction bends for each Project. The estimated materials cost (pipe and fittings) for the Fraser Gate IP pipeline is approximately $250,000, or $500 per metre, which is based on supplier quotes for a unified order for both Projects. The cost for the Fraser Gate IP pipe and fittings could be significantly greater for a standalone order. In terms of manufacturing schedule, placing a single order for pipe for both Projects will expedite the manufacturing and delivery process. Placing a smaller order for the Fraser Gate IP pipe and fittings only could result in a longer delivery timeframe depending on pipe mill manufacturing capacity.

Please also refer to the response to CEC IR 1.64.1.

65.1.1 If yes, please quantify the savings FEI anticipates.

Response:

Please refer to the response to CEC IR 1.65.1.

65.1.2 If no, please explain why not.

Response:

Please refer to the response to CEC IR 1.65.1.

65.1.3 Would there be logistical consequences for either project if the other were to be delayed, or are they independent of each other to a large extent? Please explain.

Response:

Logistically, the Projects could be constructed separately; however, the proposed Projects' scope and cost estimates are based on the assumption that the Coquitlam Gate IP pipeline is in-service prior to tie-in connections between the new replacement pipe and the existing network being completed on the Fraser Gate IP pipeline. If the tie-ins for the Fraser Gate IP pipeline are completed prior to the Coquitlam IP pipeline being commissioned, additional costs for a bypass will be required to mitigate any risk to gas supply to the customers fed downstream from the Fraser Gate IP pipeline.

66.0 Exhibit B-1, Page 132

> ***4.3.8.1 BC Oil and Gas Commission***
>
> The construction and operation of the Project are governed by the Oil and Gas Activities Act and subject to the OGC regulation. The Project requires a Pipeline Application. FEI plans to file the Pipeline Application in September 2017. A Pipeline Application is a significant process with considerable technical scrutiny on the Project by the OGC. Public and First Nations consultation, land or access rights, archaeological requirements, design reviews, environmental permits/approvals for work in and around fish bearing streams are all components of the Pipeline Application. Each component must receive OGC approval prior to the start of construction, a significant regulatory process in addition to the CPCN approval by the BCUC. Since the proposed pipeline will generally follow the existing pipeline route, the current schedule assumes a five month approval period.

66.1 Please confirm that FEI does not anticipate any major concerns on the part of the Oil and Gas Commission for the Fraser Gate Project.

Response:

Confirmed.

66.2 Please confirm that the applications for the Fraser Gate Project and the Coquitlam Project will be treated independently before the Oil and Gas Commission.

Response:

Confirmed.

67.0 Exhibit B-1-1, Appendix A-1, Page 4

> Although no in-line inspection data were available to support the reliability analysis, there was a significant amount of excavation/assessment data related to external corrosion, and these data included documentation on wall loss measurements. These excavation/assessment data served as the basis of the reliability analysis. Because the excavation data were mostly obtained from locations where prior leaks had occurred, an attempt was made to remove those features that were believed to overly-bias the dataset. Four features, consisting of one through-wall defect, two near-through-wall defects, and one feature with a much higher burst pressure value causing a spike in the data set were reviewed to justify being removed, leaving 40 corrosion features from which depth and burst pressure distributions were derived. These data were obtained from excavations on 25 individual girth weld regions.

67.1 Does removing specific data from the set being evaluated run the risk that serious but rarer potential events are not sufficiently anticipated when assessing future potential impact of risk events?

<u>**Response:**</u>

DRAS provides the following response:

When conducting sampling programs to support statistical analysis, such as the reliability assessment described in Appendix A-1 (Exhibit B-1-1), it is important to ensure that bias is not introduced into the sample dataset. If present, sampling bias will result in the samples of a stochastic variable collected to determine its distribution to be selected incorrectly, thereby misrepresenting the true distribution because of non-random reasons.

As outlined in Appendix A-1, because many of the excavation data points were obtained from locations where prior leaks had occurred, this circumstance created the potential for sampling bias, since it is likely that a disproportionate number of large corrosion features will be associated with leaking corrosion defects. Had the potential for sampling bias not been recognized, and had measures not been taken to address that potential, over-conservatism would have been introduced into the analysis.

68.0 Exhibit B-1-1, Appendix A-1, Page 4

In order to further mitigate potential sampling bias, data collected from the leak sites were excluded for the purposes of estimating the corrosion feature incident rate.

68.1 Please discuss how removing this data mitigates sampling bias and whether or not the existing known leak sites data is evidence of incident rates to date.

Response:

DRAS provides the following response:

As provided in the response to CEC IR 1.67.1, data that is representative of sampling bias should not be included in a random sample dataset that is being used as part of a statistical study such as the reliability analysis described in Appendix A-1. Because many of the excavation data points were obtained from locations where prior leaks had occurred, this circumstance created the potential for sampling bias, since it is likely that a disproportionate number of large corrosion features will be associated with leaking corrosion defects. Had the potential for sampling bias not been recognized, and had measures not been taken to address that potential, over-conservatism would have been introduced into the analysis.

69.0 Reference: Exhibit B-1-1, Appendix A-1, Page 4

> In order to determine the consequences associated with an unintended release of gas from the pipeline, two potential modes of failure were considered – leak and rupture. A 'leak' is defined as a loss-of-containment arising from a through-wall penetration of a corrosion defect, with the extent of the penetration being confined to the area of through-wall corrosion, and with no extension of the opening through instability at the edges of the flaw. A rupture is defined as a loss-of-containment that results from instability of the wall loss area, leading to the formation of fracture faces and a full-bore opening.

69.1 Please discuss the rate at which pinhole leaks would be expected to expand and increase the rate of the leaking through the loss-of containment site.

Response:

DRAS provides the following response:

The distinguishing characteristic of a leak is lack of instability at the flaw tips. Therefore, at flaw lengths that are characteristic of leaks, perforations of the pressure boundary of a pipe are mechanically stable. In the case of corrosion, therefore extension of the perforation occurs by means of ongoing corrosion. The rate of expansion of the perforation under such circumstances is controlled by the corrosion growth rate and the wall loss profile. The upper-bound mean corrosion growth rate of 0.22 millimetres per year observed in the NPS 20 IP Coquitlam pipeline is that which was associated with the first leak that occurred on that pipeline, 29 years after installation.

70.0 Reference: Exhibit B-1-1, Appendix A-1, Pages 4 and 5

The analysis showed that the probability of rupture was below the resolution of the reliability method (10^{-07}) for the twenty-year evaluation period 2013 – 2033. This is attributed to the low operating stress level of the pipeline, relative to the defect size distribution, which results in a lack of predicted structural instability through all possible combinations of defect geometry and growth period.

The probability of failure by leak increases by a factor of 3.7 through the period 2013 – 2033. The estimated failure frequencies for both leak and rupture as a function of time is summarized in Table 1 below.

Table 1
Leak and Rupture Frequencies Vs. Time

Year	Frequency of Rupture	Frequency of Leak
2013*	0	8.7
2018	0	12.8
2023	0	17.9
2028	0	23.8
2033	0	31.9

* 2013 results are provided only for purposes of a comparison against actual incident rates (note that seven leaks and zero ruptures occurred in 2013).

70.1 Would the rate of leak frequency over time be expected to be linear or should there be a curvilinear relationship over time?

Response:

The predicted leak rate over time is presented in Table 1 of Appendix A-1. That relationship is curvilinear, with a slope that increases with time.

70.2 Are the corrosion events that lead to leaks expected to continue to progress over time?

Response:

Confirmed. As supported by data and assessment included in FEI's Response to Oil and Gas Commission General Order 2013-25 included as Appendix A-3 (Exhibit B-1-1), and further described in response to BCUC IR 1.2.2, corrosion is resulting from shielding of the field-applied girth weld coating. Under circumstances of CP shielding, corrosion cannot be effectively managed or prevented by increasing cathodic protection levels in the pipeline, since shielding prevents CP currents from reaching the surface of the pipe under disbonded coating. Based on findings from FEI's condition monitoring digs, a lack of leaks at coating holidays, and recorded CP levels, FEI is confident that the CP system is operating as per design.

FEI has not identified any mitigation activities, other than replacement of the pipeline, which will prevent future leaks.

The Dynamic Risk Quantitative Reliability Assessment to which this question refers estimated that leak events would progress to become 370% more frequent by the year 2033.

70.3 Are the corrosion events leading to leaks known to be restricted to specific areas or are they expected to be potentially occurring along the length of the pipeline?

Response:

As discussed in the response to BCUC IR 1.2.2, FEI's condition monitoring digs conducted from 2011 to 2013 have established that corrosion due to 1958 construction practices is occurring along the entire length of the pipeline and at a significant majority of inspected sites. As discussed in response to BCUC IR 1.1.1.7, given sufficient time, it is expected that future leaks will be distributed along the entire pipeline length.

70.4 Why does the rate of increase for the leak frequency decline over time as a percentage increase even though the frequency of leaks rate increases in absolute terms over time?

Response:

DRAS provides the following response:

The analysis that was reported in Exhibit B-1-1, Appendix A-1, employed reliability methods, based on corrosion feature sampling distributions obtained from an excavation program. It did not incorporate a mechanistic model that predicted corrosion behaviour based on the kinetics of corrosion reactions. Because the results of the analysis as presented in Table 1 of that report do not incorporate any underlying mechanistic basis for the results, it is not possible to ascribe any reason for the predicted behaviour. As such, it is not possible to provide an answer to the question posed in this information request.

71.0 Reference: Exhibit B-1-1, Appendix A-1, Page 5

For natural gas transmission pipelines, the consequences that are associated with ruptures are much more significant than the consequences associated with leaks. In that respect, because the analysis illustrates that ruptures are not likely to occur through the next 20 years of operation, risk is associated only with leak scenarios through that operating period. It should be borne in mind, however, that with respect to leaks, the potential for adverse consequences increases with leak magnitude. This is particularly true in urban environments, where leaks can potentially migrate into adjacent buildings via subterranean pathways. The release rate associated with a leak is proportional to both the area of the hole and operating pressure. For instance, the leak rate will double with a doubling of hole area; similarly, it will double with a doubling of operating pressure. Due to a lack of data, it was not possible to comment on the range of potential hole sizes or leak magnitudes, and so it is feasible that despite the negligible risk associated with ruptures, there may be a significant operating risk associated with leaks. This is particularly true for large hole sizes and higher operating pressures. For the particular pipeline that was the focus of this study, the operating risk associated with leaks is expected to increase by a factor of 3.7 over the period 2013 – 2033.

71.1 Please discuss what the determinants of leak magnitude are expected to be.

Response:

As described in Appendix A-1 (Exhibit B-1-1), the release rate associated with a leak is proportional to both the area of the hole and operating pressure. For instance, the leak rate will double with a doubling of hole area; similarly, it will double with a doubling of operating pressure. To the extent that the presence of soil surrounding a leak can act to constrain leak rate, soil permeability can affect leak rate as well.

71.2 Why has FEI not been able to characterize the potential hole sizes and leak magnitudes?

Response:

DRAS provides the following response:

In order to accurately characterize potential hole sizes and leak magnitudes, a mechanistic model would be required that could account for all the variables that influence hole size and leak magnitude, as outlined in the response to CEC IR 1.71.3.

FEI further adds that it is not aware of the availability of such a model that could accurately predict the variables controlling hole size and leak rate as outlined in that response.

71.3 What would be required to be able to determine potential hole sizes and leak magnitudes?

Response:

DRAS provides the following response:

Leaks occur where through-wall penetration of the pipe wall occurs. The size of a hole created by active corrosion is ultimately determined by the wall loss profile and the uniformity of the progression of wall loss across that profile. Corrosion does not typically progress in a predictable manner across a uniform front and at a uniform rate across a given cross-section. Instead, it is controlled by small changes in ground chemistry, and by steel microstructure, which can cause extremely localized regions to be more anodic relative to adjacent localized regions. Therefore, corrosion tends to present an irregular surface, the shape of which cannot be accurately predicted using any mechanistic model.

As outlined in the response to CEC IR 1.71.1, beyond hole size, leak rate is also controlled by operating pressure and soil permeability. While operating pressure is readily obtainable, soil permeability changes with local ground conditions, which change along the length of a pipeline as soil type and degree of compaction changes. Soil permeability also changes with moisture content, which is influenced by changing weather conditions.

71.4 Does FEI have an estimate of the potential for leaks to migrate through the ground and into adjacent facilities and buildings?

Response:

FEI does not have an estimate of the potential for leaks to migrate through the ground and into adjacent facilities and buildings. However, please refer to the response to BCUC IR 1.1.1.3 for a description of safety issues that have arisen during past leaks on the NPS 20 Coquitlam Gate IP pipeline.

Factors affecting the potential for leaks to migrate through the ground and into adjacent facilities and buildings are provided in the response to CEC IR 1.12.1.

71.5 Have any of the leaks detected to date been of a nature such as to migrate through the ground toward buildings?

Response:

Please refer to the response to BCUC IR 1.1.1.3.

1 **72.0 Reference: Exhibit B-1-1, Appendix A-2, Page 3**

Order:

Pursuant to section 49(1)(b) of the *Oil and Gas Activities Act* (the Act), I, Dean Zimmer, order that Fortis BC Energy Inc. (Fortis BC) must:

1. On or before December 1, 2013 complete and submit to the Oil and Gas Commission (Commission):
   a. An engineering assessment of Pipeline Project 1045 (the subject pipeline) that includes but is not limited to:
      i. a timeline to repair, replace or discontinue the use of the subject pipeline;
      ii. interim measures to continue the safe operation of the subject pipeline and rationale for those measures;
      iii. a contingency plan in the event that the pipeline becomes inoperable prior to its repair or replacement;
      iv. the performance measures and defined acceptability criteria which would demonstrate fitness for service, as per CSA Z662-11, Clause 3.3;
      v. description of the leak detection program and its efficiency;
      vi. all information obtained from cut-outs of the subject pipeline performed within the last ten years that provides evidence of the subject pipeline condition;
      vii. the cause, size, and axial location of the through-wall failure, and the integrity of the surrounding material for each failure in 2013.

   b. An estimate of the volume of gas lost during the most recent leak;

   c. Records of the closed interval surveys of the cathodic protection system for the past five years, and;

   d. A map of the subject pipeline that shows all failure locations over the past five years.

2. Complete leak surveys on the subject pipeline at a minimum of once per week.

3. Submit the information required in Item 1 electronically to the Commission at C&E@bcogc.ca.

2

Reasons:

I make this order for the following reasons:

i. Fortis BC is the operator responsible for the subject pipeline.

ii. The subject pipeline has experienced seven leaks to date in 2013, two leaks in 2012, and six leaks prior to that.

iii. Fortis BC has identified external corrosion as the cause.

iv. I am of the opinion that the subject pipeline may pose a risk to public safety and the environment.

72.1 Please discuss how the pipeline may pose a risk to public safety.

Response:

Any time there is a release of gas underground there is the potential for the gas to migrate and accumulate in an enclosed space. If a sufficient amount of gas accumulates and a source of ignition is present, the gas can ignite or explode, which presents a safety risk to those in proximity. FEI's leak detection program is designed to manage safety risk by detecting any gas releases before a significant volume of gas is released and mitigates the potential for significant migration or accumulation. Please also refer to the response to BCUC IR 1.1.1.3 for a description of safety concerns associated with past leaks on the existing NPS 20 Coquitlam Gate IP pipeline.

73.0 Reference: Exhibit B-1-1, Appendix A-5, Pages 1 and 2

> ***Methodology***
>
> Broadly, four types of mutually exclusive costs are considered and aggregated as below. It should be noted that any costs that would be incurred both with and without the Projects are
>
> not considered (for example, repair costs as a result of third party damage are not included as these costs are expected to be incurred both with and without the Projects). However, there are also repair costs associated with the ongoing response and repair of leaks that will be mitigated with the replacement of the Coquitlam Intermediate Pressure pipeline. These avoided costs are not included in this assessment.

73.1 Please explain why repair costs for leaks are not included in the assessment.

Response:

The same failure rates for the “as is” and “reference” pipelines are used in the analysis as these are average failure rates that can be applied over the 60 year analysis period. This failure rate is for leaks large enough to require isolation of the affected segment. Repair costs for a NPS 20, NPS 24 or NPS 30 pipeline are not significantly different for this type of leak. Therefore, for the purpose of this assessment, the risk associated with pipeline repairs for the “as is” and “reference” scenarios are considered comparable; the inclusion of repair costs for leaks would not add any significant refinement to the analyses. For this reason repair costs were not considered in the consequence assessment.

73.2 Please confirm that these avoided costs would be part of a comprehensive avoided costs analysis but that the report is focused on isolating particular types of avoided cost as a matter of mandate.

Response:

A comprehensive avoided cost analysis for a given scenario might consider additional costs, but, as noted in the response to CEC IR 1.73.1, such an analysis is not required for a consequence analysis that assesses the difference between the before (“As-Is”) and after (“Residual”) cases.

1 **74.0 Reference: Exhibit B-1-1, Appendix A-5, Page 2**

A. Direct Fixed Expenditures as a Consequence of an Outage. These represent costs incurred in the event of any outage event that impacts a significant number of customers. These costs include expenditures associated with regulatory response, public opinion, government relations and customer loyalty programs. Based on FEI estimates, these are in aggregate expected to fall in a range of $480,000 to $4.75 million per outage.

B. Relight Costs. Relight costs, which are defined in this study to include shutdown, purging and relight cost, depend on the scale and location of the outage, resource availability, and unit costs of manpower and related resources. FEI has estimated the number in each customer class affected for each scenario, an appropriate relight schedule based on best efforts resource deployment, and the resultant costs of relighting customers. Resources for relight are deployed immediately after an outage but it is assumed that customers will have no service for at least a five day period during which the location and cause of the outage is identified and repaired – or is circumvented – to bring service back to impacted customers. The maximum impact identified is a failure in the Nichol to Roebuck segment; some 252,300 customers would be without gas for up to 25 days and the 18 day relight period would involve direct expenditures of approximately $29 million.

C. Revenue Loss. FEI will experience direct revenue losses through two mechanisms: (i) the outage event will reduce sales revenues depending on the

2

duration of the outage, the estimated demand during the outage by a customer, and the applicable tariff (including cost of service [COS]) but excluding commodity cost; and, (ii) a potential long term revenue loss associated with the loss of some proportion of customers that were interrupted. Demand was estimated based on average customer demand profiles as presented in the FEU Long Term Resource Plan (LTRP, 2014) for the year 2016. A credible worst case scenario placed the disruption at the peak demand days associated with a December outage. A credible worst case benchmark scenario for long term revenue loss was developed based on the loss of annual sales from 10% of the customers interrupted for more than 10 days as a consequence of the outage.

3

D. Service Disruption. Service disruption was calculated using methods relying on estimated economic welfare losses to each different customer class. The welfare loss calculation is based on literature values associated with the willingness to accept compensation (WTAC) relating to the unplanned loss of a marketable commodity. A literature survey showed that such values are typically of the order of 3-10 times the price paid for the commodity (regarded as a revealed willingness to pay [WTP]). A criticality scale was developed that corresponded to higher WTAC/WTP ratios for safety and health issues. Service disruption costs are also sensitive to fuel switching opportunities that individual customer classes may typically have to address interruptions. Residential customers exhibited the highest ratios or multipliers; large interruptible customers potentially exhibit the lowest ratios because they potentially switch more readily. These disruption impacts are regarded as an appropriate proxy for incremental economic impacts.

The impacts exclude those that might be associated with disruptions of supply to potential expansion of LNG capacity in the BC Lower Mainland (either for export or domestic use).

74.1 Please estimate the cost impacts in the event that new LNG capacity projects, both domestic and export, are operational and describe the assumptions used.

Response:

HJ Ruitenbeek Resource Consulting Limited provides the following response:

Quantitative consequence impacts relating to future LNG production in the province were excluded from the scope of the Economic Consequence Analysis. Such an analysis would require considerable speculation that is not readily modeled.

74.2 Please confirm that one of the avoided costs of the Upgrade Project would be an assumed future replacement of the NP 20 at 1200 kPa.

Response:

HJ Ruitenbeek Resource Consulting Limited provides the following response:

Not confirmed. In the context of the economic consequence analysis, results would not be sensitive to the existence (or not) of a future replacement. Costs were therefore not included.

75.0 Reference: Exhibit B-1-1, Appendix A-5, Page 3

Table ES-1a. Estimated potential customer outages without LMSU Projects ("As Is")*

	Customers	Residential	Commercial	Industrial	Other
Nichol to Roebuck	252,300	223,641	27,546	1,053	60
Roebuck to Delta	252,300	223,641	27,546	1,053	60
Delta to Tilbury	229,690	203,471	25,181	991	47
Tilbury to Fraser	215,200	190,373	23,823	970	34
IP Segment 1	171,000	151,945	18,234	801	20
IP Segment 2	98,200	83,947	13,635	602	16
IP Segment 3	14,100	13,479	571	48	2
IP Segment 6	12,500	11,972	490	38	0
IP Segment 7	12,500	11,972	490	38	0
IP Segment 10	2,840	2,625	210	5	0
IP Segment 13	29,620	26,694	2,831	90	5
Cape Horn to Coquitlam	163,280	149,954	13,134	161	31
Port Mann to Cape Horn	163,280	149,954	13,134	161	31
Nichol to Port Mann	172,572	158,280	14,058	200	34

Table ES-1b. Estimated potential customer outages with selected upgrades ("Residual")*

	Customers	Residential	Commercial	Industrial	Other
Nichol to Roebuck	81,300	71,696	9,312	252	40
Roebuck to Delta	81,300	71,696	9,312	252	40
Delta to Tilbury	58,690	51,526	6,947	190	27
Tilbury to Fraser	44,200	38,428	5,589	169	14
IP Segment 1	0	0	0	0	0
IP Segment 2	0	0	0	0	0
IP Segment 3	0	0	0	0	0
IP Segment 6	0	0	0	0	0
IP Segment 7	0	0	0	0	0
IP Segment 10	2,840	2,625	210	5	0
IP Segment 13	0	0	0	0	0
Cape Horn to Coquitlam	121,880	112,744	9,086	27	23
Port Mann to Cape Horn	121,880	112,744	9,086	27	23
Nichol to Port Mann	131,172	121,070	10,010	66	26

* Notes:

IP Segments 4, 5, 8, 9, 11 and 12 can be isolated and would not be subjected to any disruptions in service either before ("As Is") or after ("Residual") any of the upgrade Projects are undertaken. The residual outages shown here correspond to the impacts after the IP System upgrades are undertaken; inspection shows that up to 171,000 customers are protected from a failure in the Nichol to Fraser segments and 41,400 customers are protected from a failure in the Nichol to Coquitlam segments.

Customer counts exclude potential new LNG customers.

75.1 Please indicate whether or not these customer estimates are fixed estimates as of a single point in time and specify the date applicable to the estimates.

Response:

The estimates can be regarded as a representative year within the next decade, as they are based initially on customer profiles from FEI projections, coupled with information about FEI's current service area and customer base to determine the potential scope of outages. As noted in Appendix A-5 (page 15): "*Customers were categorized by rate class and a Reference Case was developed that used information from demand forecasts in the LTRP (2014) with 2016* *taken as a base year for demand estimates.*" The outage numbers were based on FEI modeling of the system in mid-2014. The outage results and demand structure are used for modeling purposes and are considered representative for the purposes of this Application.

75.2 Please indicate whether or not the potential affected customers "with selected upgrades", "residual" would change over time as the population using the natural gas distribution system increases.

Response:

Yes, customer numbers provided are based on accounts existing at the end of 2013 and are increasing with time.

Both the "As Is" and the "Residual" customer counts would potentially change over time. FEI notes that they would change in the same direction. At this stage it is important to note that the purpose of the Economic Consequence Analysis is to serve as an input to valuation of an estimate of changes in operational risk (Appendix A-10). That estimate relies on a change in risk from a "before" scenario to an "after" scenario: the ∆Risk estimate is concerned with the difference in the "As Is" and "Residual" consequences (weighted by failure frequency). FEI notes, therefore, that the ∆Risk is not as sensitive to overall increases or decreases in demand because the "As Is" and "Residual" estimates are positively correlated for population increases. As noted in the response to CEC IR 1.75.1, these point estimates are regarded as representative for estimating consequences; Appendix A-5 (page 15) shows they correspond to estimated demand in 2016. FEI regards this as a reasonable basis for estimating conservative (e.g., lower bound) consequences.

76.0 Reference: Exhibit B-1-1, Appendix A-5, Pages 8 and 9

> The project scope focuses on those costs directly associated with outages. As Is consequences are before any upgrades associated with the LMSU Project. Without the LMSU Project there will remain system reliability concerns, which could result in outages for some customers. Costs that are common in both scenarios (such as system repair costs in event of a line shutdown) are excluded from this analysis. It is important to note that this analysis does *not* imply that the possibility of a line shutdown has been eliminated. With the LMSU Project unplanned line shutdowns are still possible (e.g., from a leak or a rupture), but there would be sufficient redundancy in the system to serve the customer base without a service disruption.[2] It should also be noted that the costs addressed within the scope of this analysis are those that will be subjected to probabilistic weighting within the risk analysis. There are other costs and benefits that would normally inform any eventual overall project cost-benefit analysis: the LMSU Projects will, for example, result in definite (100% probability) avoided O&M costs but these costs are not captured by this analysis.

76.1 Please provide an estimate of the O&M costs which the LMSU Projects will avoid, and when these will occur.

Response:

The base O&M embedded in the PBR formula does not account for the forecast level of O&M that would be incurred in the absence of these Projects. Thus, on a formulaic O&M basis there are no avoided costs associated with the Coquitlam IP or Fraser Gate IP Projects.

Please refer to the responses to BCUC IRs 1.7.1, 1.24.1, 1.24.1.1 and 1.24.2 for avoided incremental O&M costs associated with the Coquitlam Gate IP Project as compared to the status quo.

There are no avoided O&M costs associated with the Fraser Gate IP Project as compared to the status quo.

76.2 Please clarify whether in the event of a significant outage of NP 20 at 1200 kPa the scenario includes implementation of a bypass to restore service and if so whether those costs are included.

Response:

For the purpose of the risk assessment it was assumed that a failure would result in the release of a significant volume of gas requiring the isolation and blow down of the segment as soon as possible. Valves upstream and downstream of the leak would be used to isolate the segment. The time to install a bypass would be too great to be used for this type of unplanned event. Repairs of these types of leaks could not be conducted on the pipeline segment while it was still in service. Restoration of service to customers would be required after repairs were made to the pipe if adequate system resilience was not available.

Repair costs have not been included in the consequence calculations for either the before or after cases used in the risk assessment as these costs would be similar.

76.3 Please comment on whether or not a significant outage of NP 20 at 1200 kPa would be likely to advance a planned later replacement project.

Response:

It is unlikely that the current schedule to replace the NPS 20 Coquitlam Gate IP pipeline could be shortened.

77.0 Reference: Exhibit B-1-1, Appendix A-5, Page 11 and Appendix A-2, Page 3

This Section introduces and discusses a number of economic evaluation concepts relevant to estimating the economic impacts of an outage.

Reasons:

I make this order for the following reasons:

i. Fortis BC is the operator responsible for the subject pipeline.

ii. The subject pipeline has experienced seven leaks to date in 2013, two leaks in 2012, and six leaks prior to that.

iii. Fortis BC has identified external corrosion as the cause.

iv. I am of the opinion that the subject pipeline may pose a risk to public safety and the environment.

77.1 Please discuss whether it would be relevant to evaluate a concept such as the loss of reputation for a utility as a reliable supplier of natural gas service.

Response:

HJ Ruitenbeek Resource Consulting Limited provides the following response:

Reliability and reputation are relevant concepts. Most utilities have programs that are aimed to attract and retain customers: any disruption in the reliability of service could negatively impact the ability to attract new customers or retain existing customers. Within the context of the evaluation work conducted for this Application, Appendix A-5 has incorporated aspects of this through discussion of "Loyalty" benefits and through the evaluation of potential long-term revenue loss to FEI as proxies for this style of reputational loss.

The "Economic Consequence Analysis" Appendix A-5 (page 17) notes:

> *These [fixed] costs are consistent with those prepared during the Huntingdon CPCN, although some were revisited and further improved. First, all costs are now described in two levels where fixed costs are less if fewer customers are impacted. The Huntingdon estimates previously considered only one single large outage, whereas this report treats 14 scenarios of varying scales. Second, expenditures on customer loyalty programs were revisited and increased to place these on a comparable level to expenditures on public awareness programs. These customer loyalty expenditure levels are regarded as necessary to retain customers and provide some moderate assistance for any inconvenience. It is acknowledged that some customers may still inevitably choose to reduce their future reliance on natural gas usage as a consequence of the interruption;*

these longer term impacts on customer numbers or customer usage are treated explicitly below as potential long term revenue losses to the utility.

The discussion relating to potential long term revenue loss continues in "Economic Consequence Analysis" Appendix A-5 (page 19-20). A sensitivity analysis (Sensitivity I) in Section 4 deals with a specific case that assumes permanent loss of some customers and for the largest outages shows an increase in economic consequences of 39%.

77.2 Please discuss whether there is any literature on the value of corporate reputations or goodwill based on continued reliable service and how that may be affected by a catastrophic worst case scenario, particularly where the OGC has opined that the pipeline may pose a risk to public safety and the environment.

Response:

FEI has not undertaken a literature survey on the general concepts of corporate reputations, goodwill, service reliability and catastrophic occurrences. Nor does not it believe that such a survey would greatly inform the Application. FEI is aware of the role of loyalty (or goodwill) and service reliability in terms of corporate financial applications and that has been incorporated as described in the response to CEC IR 1.77.1.

FEI notes that worst case scenarios still need to be reasonable or credible to be of analytical value. The types of utility outages modeled in Appendix A-5 and A-10 in this Application are rare events that do not generate substantial literature. A selected survey of outages was conducted and presented in Appendix A-10 (Annex C – Selected Disruptions to Energy Services in Canada); this survey was conducted to document impacts and responses for a sample of incidents.

77.3 Please discuss whether there would also be a potential value for the reputation of the BC Utilities Commission if a worst case event were to occur during a time when the Commission may not have approved a proposed upgrade project, particularly where the OGC has opined that the pipeline may pose a risk to public safety and the environment.

Response:

FEI is not in a position to comment on the potential reputation risk to the Commission due to its decisions.

77.4 Please discuss whether or not these reputation risks and potential losses would be significantly reduced with the approval of one of the feasible alternatives.

Response:

Approval of the Projects as proposed will reduce the risk of disruption in service to customers, which in turn could be expected to reduce the risk to loyalty as described in the response to CEC IR 1.77.1.

78.0 Reference: Exhibit B-1-1, Appendix A-5, Page 13

> For current consumers of a product, the current market price is an appropriate measure of a revealed WTP. A loss of economic wellbeing can be approximated by the difference between the WTAC and the price of the commodity.[8]

78.1 Please comment on whether or not the current market price of a substitute commodity, such as electricity or wood biomass, for space heating might also provide a useful and appropriate measure of a revealed WTP.

Response:

HJ Ruitenbeek Resource Consulting Limited provides the following response:

Willingness to pay (WTP) is a measure of how much an individual would be willing to give over in income to have an extra unit of a good. There are numerous ways to estimate WTP. The least reliable are techniques that simply ask a question through a constructed market for goods or services that have no market prices. The most reliable are where individuals voluntarily and recurrently hand over some part of their income for a commodity: that is termed a "revealed WTP". However, even within the category of revealed WTP, there are differences in reliability. The most reliable is when payment is made for a product at its own price. Less reliable would be to use the price of a substitute good. For example, gas price is a good indicator for the revealed WTP for gas. Electricity price is a good indicator for the revealed WTP for electricity. Electricity (or wood biomass) price may also serve as a proxy for estimating WTP for gas *if there were no market prices for gas* in certain areas. The proxy is still just an estimate however that may need to be adjusted for other factors or qualities of the good. Given that in this analysis, the customers being assessed are gas users paying a gas price, the gas price is the most appropriate basis for valuation.

79.0 Reference: Exhibit B-1-1, Appendix A-5, Page 16

All costs are incurred within a short period associated with the disruption event. An exception to this involves an estimate of long-term revenue losses. To place these losses in present value terms, a 7%/yr real discount rate was selected to discount them to the time of the hypothetical disruption event. This Reference Case discount rate is consistent with current practice in cost

79.1 Please explain the derivation of the 7%/year real discount rate for the FEI circumstances.

<u>Response:</u>

HJ Ruitenbeek Resource Consulting Limited provides the following response:

The derivation continues on the same and following (page 16) of Appendix A-5 as follows:

All costs are incurred within a short period associated with the disruption event. An exception to this involves an estimate of long-term revenue losses. To place these losses in present value terms, a 7%/yr real discount rate was selected to discount them to the time of the hypothetical disruption event. This Reference Case discount rate is consistent with current practice in cost benefit analysis, and is regarded as appropriate given the opportunity cost of capital and other factors such as consumer time preference. It may different from rates used for other purposes in the regulatory setting; commonly rates used in tariff determination, for example, will be financial discount rates expressed in nominal (as opposed to real) terms and consider primarily different weightings to various sources of capital.

In addition, please refer to Appendix A-5 (page 6) and Footnote 6, which provide further background to this derivation:

[6] In treating costs similarly, some caution is warranted in the use of discount rates. The economic literature and guidance from some authorities (e.g., Treasury Board of Canada 2007, pp 37-38) would generally recommend using lower discount rates for cash flows associated with conditional or uncertain damages experienced by individuals because such discount rates would be more driven by consumers' social rate of time preference, currently estimated at 3%/year for Canada. In this report, FEI has selected 7%/year as an appropriate discount rate but sensitivity analyses at a lower rate are considered in Section 4. We stress that this is a social discount rate that applies only to the vector of future income losses discount to the time of the event; other losses are confined to the duration of the event and are not discounted. This discount rate will normally differ from financial rates of discount that may be used in regulatory settings such as the setting of tariffs.

79.2 Please provide assumptions with respect to inflation and FEI WACC for the relevant period, including borrowing cost and allowed ROE.

Response:

FEI notes that the WACC and ROE are not used in the determination of the discount rate for the purposes of the Appendix A-5.

The requested information, however, is as follows:

- Inflation – Assumptions regarding inflation rates and the Company's capital structure and cost of capital were not used in Appendix A-5, The Economic Consequence Analysis. The following requested information on inflation rates and FEI WACC which were used in Confidential Appendix E are as follows:

Assumptions for Inflation Rates

	2013	2014	2015	2016	2017	2018	2019	
CPI Rate	0.93%	1.46%	1.30%	2.42%	2.34%	2.36%	2.30%	2.30% for all years thereafter
Material Inflation	2.00%	2.00% for all years thereafter						
Labour Inflation	3.00%	3.00% for all years thereafter						
Capital inflation	4.50%	4.50% for all years thereafter						

- Capital Structure & Cost of Capital - Please refer to the response to BCUC IR 1.22.9 regarding the capital structure, embedded rates of return and the Company's after-tax WACC.

80.0 Reference: Exhibit B-1-1, Appendix A-5, Page 17

> Relight costs depend on the scale and location of the outage, resource availability, and unit costs of manpower and related resources. FEI has estimated the number in each customer class affected for each scenario, an appropriate relight schedule based on best efforts resource deployment, and the resultant costs of relighting customers. Table 3.3 provides a summary of the "As Is" relight assumptions and expenditures; Annex Table B2 provides full details of different cost components for both the "As Is" and "Residual" consequences.

80.1 Please provide the number of Tech resources expected to be available in the event of the maximum scale outage and the anticipated unit cost of such resources used as well as any related resources.

Response:

Based on the largest outage scenario on Table 3.3 of Appendix 5, FEI would mobilize approximately 500 resources, over half of which would be from outside the Company. The estimated cost of external resources is similar to FEI resources with the addition of travel and expenses for those residing outside the Lower Mainland. The total overall financial cost for the shutdown and relight would be approximately $120 per outage customer.

It should also be noted that actual resource allocation will depend on specific circumstances surrounding the outage. FEI would adapt and manage its resources at the time of any disruption with a view to reducing the potential consequences.

80.2 Please discuss whether or not advance preparation for such an event including importing qualified Tech resources from other utilities might reduce relight times and or estimated repair times.

Response:

Importing additional qualified Tech resources will reduce outage duration. The numbers provided in the response to CEC IR 1.80.1 include resources from local contractors and from 16 other mutual aid utilities.

80.3 Please discuss whether or not FEI has done any tradeoff examination of the costs of potentially faster response versus the perceived avoided costs of longer delay times.

Response:

No specific optimization or tradeoff analyses have been conducted. FEI considers the resource levels noted in the response to CEC IR 1.80.1 to represent a reasonable estimate of the maximum resources that could be effectively deployed and managed in an outage event of this magnitude. Cost of resources was not a primary consideration in the resourcing level estimates.

80.4 Please describe any reciprocal or other support arrangements FEI has with other utilities, which could potentially be a source of competent resources in the event of an emergency outage of the nature being contemplated.

Response:

The numbers provided in the response to CEC IR 1.80.1 include utilizing resources from local contractors and the 16 utilities with which FEI has mutual aid agreements.

81.0 Reference: Exhibit B-1-1, Appendix A-5, Page 18

> [10] FEI does carry insurance coverage but these are not taken as an offset in this analyses because they represent simply a redistribution of costs and in any event may in due course result in a change in premiums or availability of cover (which are also not reflected in this analysis). FEI currently holds relight coverage subject to a 10 day waiting period to a limit of $30 million.

81.1 Please provide the annual insurance cost estimate for the relight insurance coverage.

Response:

The annual insurance cost for relight insurance, a sub-limit under the property policy, is not broken out separately by insurance underwriters.

81.2 Please provide the rationale behind the 10 day waiting period and any assumptions that may be required to be met by the utility to qualify for the insurance.

Response:

A 10 day waiting period is the deductible required by insurers. FEI assumes a Maximum Foreseeable Loss (MFL) of $30 million; therefore the limit of coverage provided is $30 million. The limit is negotiable with insurers.

82.0 Reference: Exhibit B-1-1, Appendix A-5, Page 18

> Event Losses. Demand was estimated based on average customer demand profiles as presented in the FEU Long Term Resource Plan (LTRP, 2014) for the year 2016. A credible worst case scenario placed the disruption at the peak demand days associated with a December outage; on average this implied that normal gas use during the outage period was about 2.3 times the average daily gas use. Lost revenue during the event was based on applicable tariffs for each customer class in mid-2014. For each customer class an average representative tariff was used to represent the sales price to the customer of the gas. The sales price included the commodity cost ($4.64/GJ) and a cost of service (COS) element using loads for a typical customer in that class. Table 3.4 summarizes these parameters. The revenue loss

82.1 Please discuss whether or not the utility would have contracts in place for gas supply and whether or not, in the event the gas was not used as anticipated, it may need to be sold in the market and if so discuss the quantities and prices that it might be sold for in such an event.

Response:

Any gas sales that resulted would be done under existing gas contracts that FEI has in place with other counterparties and would be done at market prices.

Note that the above citation continues:

> *The revenue loss for any customer class was calculated based on the foregone gas deliveries multiplied by the COS [Cost of Service] for any given customer class.*

The analysis in Appendix A-5 thus assumes that there is a spot or futures market for gas at the time of the disruption that would result in no net liability to the utility. FEI notes that the selected assumption may tend to understate the economic consequences of a gas disruption. FEI is unable to speculate on what the market circumstances may be at the time of any potential future disruption.

83.0 Reference: Exhibit B-1-1, Appendix A-5, Page 19

> To validate the assumptions, these results can be compared to a behavioural model in which a customer considers the life cycle costs of natural gas by including the cost of a temporary disruption within the average price of gas over a fixed period. A risk averse customer would reasonably allocate the temporary service disruption costs (described below) for an assumed "personal credible worst case" disruption over a decision period. We take a decision period to be 15 years, representing conservative estimates of the typical life of a mix of natural gas assets including water heating and furnace equipment (based on Lekov *et al.* 2010), and assume that our risk averse customer predicts one such event will disrupt her for one month over this period. This scenario is equivalent to an 11.3% long-term price premium on the purchase of natural gas by our customer. In OECD countries generally, surveys suggest that long-term own-price elasticities for natural gas approach -0.5%,[12] implying that this scenario would generate a 6-7%

> Lekov A, Franco V, Meyers S, Lawrence Berkeley National Laboratory. 2010. Economics of Condensing Gas Furnaces and Water Heaters Potential in Residential Single Family Homes. 2010 ACEEE Summer Study on Energy Efficiency in Buildings. Pp 9-180 to 9-191.

83.1 Please discuss the calculation and derivation of an 11.3% long term price premium.

Response:

HJ Ruitenbeek Resource Consulting Limited provides the following response:

The price premium is an approximation based on the simulations for a risk averse customer. The risk aversion can be reflected in an individual's perceptions of the criticality of gas, frequency of incidents, duration of incident, and timing of the incident. This is not the same as a "worst case incident" for the system; this is a perspective of the worst off individual in the event of a worst case incident on the system.

The implicit assumptions for this individual are that the WTAC/WTP multiplier (as described in the Service Disruption section page 15) reaches the maximum level of 10 for a residential customer. This corresponds to the highest perception (by the individual) of the criticality of the gas service. Adjusting for the reference price (P_r), this implies that the welfare loss (ΔWelfare) for such a customer would be 9*P_r. Recall that, as shown in the derivation of the average ΔWelfare in Table 3.5 the assumed multiplier for all residential customers is 7.22

The risk averse nature of this individual is such that she expects to lose service for one month over a 180 month (15 year) period. This behaviour is risk averse because the actual occurrence of such a long disruption is likely to be less frequent; even if a disruption of this length occurred, it implies that she would be one of the last ones relit. For her to be one of the "median" customers relit would imply that the disruption of service to all customers would need to approach two months: the Reference cases in this study did not involve a two month relight period. Incorporating an assumption of one month in 180 being disrupted, this implies that – for her – the price premium over the undisrupted 179 months would be equivalent to about $9*P_r/179$ or about $0.05*P_r$. This corresponds to about a 5% price premium over the long term based on the assumptions to this stage.

However, this also assumes that she is indifferent over when the interruption occurs in the year, or that she has the same demand for gas every day of the year. She is neither indifferent, nor is the structure of her gas demand constant every day of the year. She is risk averse: she is most concerned about peak day demands in the expected cold months. For this risk averse individual, the price premium paid on every unit of gas in the year must reflect this distribution. A final adjustment is thus made for load shape for this customer and the length of the outage. In the Lower Mainland, the multiplicative factors for disruptions of this nature given the load shapes in the residential rate classes are of the order of 2.2 to 2.4, corresponding to price premiums in the range of 11% to 12% of P_r. The larger disruptions modeled for this Study placed the median close to the lower part of this range with a load shape adjustment of about 2.25: this yields a price premium of approximately 11.3% ($2.25*9*P_r/179$).

83.2 Please discuss the appropriateness of the assumption of one "personal credible worst case" disruption being determined by customers to be 1 in 15 years.

Response:

HJ Ruitenbeek Resource Consulting Limited provides the following response:

This is regarded as appropriate, as the assumption in effect provides a behavioural model for somebody that is risk averse and regards themselves as needing the gas for critical applications. As described in the response to CEC IR 1.83.1, the risk averse nature of the behaviour comes across in the 15 year period: this is considerably more frequent than the actual likely incidence of such an event. On the other hand, for the individual herself this may be regarded as a reasonable assumption. Individuals routinely make life cycle decisions over equipment based on their perceived worst case.

83.3 Please discuss the number of 25 day relight periods for this number of customers that have occurred in North American gas distribution systems over the last 50 years and the approximate total number of customers receiving natural gas service.

Response:

FEI does not have access to the requested information. FEI does note that relights of this magnitude are a rare, but possible event. As noted in the response to CEC IR 1.90.2:

> *A review of the metadata associated with the PHMSA incident data cited in the response to CEC IR1.90.1 indicated that where shutdown occurred, the shut down period exceeded 15 days 7% of the time. It should be noted that where significant numbers of relights are required, even very short pipeline repair periods can result in extensive shutdown periods.*

83.4 Please discuss FEI's experience with relight periods and the number of such significant worst case losses FEI has experienced.

Response:

Over the past 10 years, FEI has experienced 5 outages ranging in size from 442 to 1,297 customers. The relight period of these outages has been 2-3 days.

83.5 Please discuss whether or not long term loss scenarios would involve customers in considering alternative costs of substitute services and what those might be.

Response:

HJ Ruitenbeek Resource Consulting Limited provides the following response:

There is a significant literature on energy demand and switching to other services. The literature reflects that long-term choices are a function of numerous factors including income, fuel prices, prices of energy using goods, fuel flexibility, perceived reliability of the equipment or fuel supply, regulatory incentives, the economic life and durability of the energy-using goods, perceived or real externalities (associated with greenhouse gases or pollution for example), and familiarity with specific fuel types and equipment. A discussion of all possible loss scenarios is beyond the scope of this Study and is not necessary for understanding the reasoning behind the potential loss of revenues from people who decide to switch permanently away from gas.

83.6 Please discuss the requirement over time for a customer retain in memory an estimate of a personal cost impact and whether or not such memory would likely fade with time diminishing to zero.

Response:

HJ Ruitenbeek Resource Consulting Limited provides the following response:

The analysis undertaken of the “risk averse” customer is regarded as a tool for modeling and understanding behaviour. Whether memory fades, diminishes, or reaches a quantitative state of “zero” is not material to the model. The model seeks to understand whether a given customer might or might not stay a customer after there has been a service disruption involving the use of a durable good; welfare impacts are translated into a price signal to determine the extent or likelihood of changes in behaviour. The eventual change in behaviour can generally be regarded as a binary decision that does not necessarily involve memory. As described in the response to CEC IR 1.83.5, numerous factors can contribute to this decision some of which will be short-term (prices and expected prices at the time that the decision needs to be made) and some of which may rely on past experience or familiarity with the equipment being used.

83.7 Please supply the referenced Lekov 2010 paper.

Response:

HJ Ruitenbeek Resource Consulting Limited provides the following response:

Please refer to Attachment 83.7.

84.0 Reference: Exhibit B-1-1, Appendix A-5, Page 20

> The maximum service disruption consequence anticipated is approximately $256 million and is again associated with a malfunction involving locations between the Nichol Valve Station and the Delta Valve Station. The impacts of this service disruption are primarily borne by the residential sector: approximately $170 million across some 224,000 residential customers. The reader is reminded that this assumes a relight schedule that does not give priority to any given customer. Critical customers are not identified as such and would be connected at any time during the period.

84.1 Please discuss whether or not disruption of service proxy economic impacts would be affected by potential mitigation scenarios for space heating impacts and water heating impacts.

Response:

HJ Ruitenbeek Resource Consulting Limited provides the following response:

For any type of service disruption to any form of critical infrastructure, there are potential mitigation scenarios that could reduce some of the impacts on customers and on the utility. These mitigation measures can involve improved public awareness, readiness for emergency response, and arrangements with other service providers. Each incident will be different and will pose certain challenges.

The Economic Consequence Analysis does not address specific mitigation strategies (including heating impacts). The report does, however, discuss general "Coping Strategies and Mitigation" issues qualitatively (Page 14); this section highlights that mitigation options are typically few over a short-term period, such as that associated with a utility service disruption. The reasonable worst-case scenario approach adopted in the analysis thus reflects limited mitigation opportunities but, as noted, the relight assumptions reflect a best-efforts basis for reconnecting disrupted customers: "FEI created a credible scenario that includes mobilization of available additional resources to limit service disruption and lengthy outage periods (page 14)." The report also addresses related issues quantitatively through a treatment of criticality (page 20) and the role of criticality in sensitivity analyses (pages 21-22 "Sensitivity V"). The sensitivity analyses conducted, for example, showed that "for a Nichol-Roebuck failure scenario (in which 252,300 customers are impacted) … a 10% decrease in the most vulnerable residential, commercial, and small industrial uses reduces potential economic consequences by about 6% (page 22)." Additional results are provided in Table 4.1. The report also notes that while "…the sensitivities show a decrease compared to the Reference Case, … an increase in criticality would similarly increase the costs (page 22)."

84.2 Please discuss what potential residential and other customer class mitigation scenarios were considered.

Response:

Please refer to the response to CEC IR 1.84.1.

85.0 Reference: Exhibit B-1-1, Appendix A-5, Page 21

> The reference case consequence estimates are regarded as appropriate for decision making to the degree that they show relative scales of consequences among categories and locations. Sensitivity analyses can further inform decision-making as they demonstrate that costs can readily be significantly higher in the event that some assumptions are relaxed within credible limits. For discussion purposes we describe these here only for the "As Is" consequences.

85.1 Please discuss whether or not there may be appropriate sensitivity cases below the reference case other than Sensitivity Case V and if so what those might be.

Response:

HJ Ruitenbeek Resource Consulting Limited provides the following response:

Other sensitivity cases were considered but the general approach was to start with a credible or reasonable worst case *Reference* scenario and then conduct the initial analyses – and subsequent sensitivity analyses – based on that scenario. Such a *Reference* scenario implies that possibly 90-95% of actual incidents will not be as bad as the selected *Reference* scenario. In other words, there are numerous cases "below the reference case" but analyzing them will not necessarily proffer further insights.

The scenarios selected, for example, are based on an incident that occurs on a cold day of peak demand, or at a time such that the relight schedule extends through a peak demand period: this covers a number of months through the BC winter. If the disruption were to occur in summer or near the end of winter, consequences would be lower.

Another potential scenario would involve changing structure of demand. The analyses clearly reflect that the highest consequence value per GJ of gas is to residential users. If demand structure were to change with a greater share in industrial uses then one might expect lower consequences in event of a supply disruption.

The alternative analyses described (summer disruption, shift to industrial demand) may be possible, but they would not necessarily provide additional information of value to the risk analyses that depend on the Economic Consequence Analyses.

Accordingly, the sensitivities presented provide appropriate scope for analysis within the context of this Application.

85.2 Please discuss why only sensitivity cases above the reference case apart from Sensitivity Case V were examined.

Response:

Please refer to the response to CEC IR 1.85.1.

85.3 Please discuss the degree of certainty in each of the components of the cost estimates and whether or not it might be reasonable to expect a wide degree of variability in the final estimates.

Response:

HJ Ruitenbeek Resource Consulting Limited provides the following response:

As noted in the response to CEC IR 1.85.1, there is significant potential variability in the final costs arising from any given incident. The nature of the analysis is to determine a reasonable or credible worst case. As such, point estimates were made for the most critical elements including the number of customers impacted, the shutdown times, the structure of demand, and input costs associated with addressing the impacts. Confidence intervals were not established for individual cost centres, primarily because many of them are interdependent. Also, the fact that the events being investigated are fundamentally rare makes it more difficult to establish confidence intervals. The most sensitive items are those described in the Sensitivity analyses, which indicate that variability could readily increase consequences by factors of two or greater in some circumstances.

FEI does know that the basis for its internal costs in event of an outage are reasonably well established. Loss of COS revenue can be estimated with high precision due to an existing tariff structure. It is aware of its internal and external courses in the event of a relight exercise, yet the analyses have also added a 30% contingency to those to represent uncertainty in the circumstances of the relight. Disruption costs to consumers are uncertain because of assumed criticality; sensitivity analyses show the impact of changing criticality assumptions. Long-term revenue losses are perhaps the most speculative because they relate to consumers and generations that cannot be identified, or whose habits may differ considerably from that of current customers.

The uncertainty in some of these estimates should not detract from the role that the analyses are intended to play. By informing the risk analyses, the consequence analyses show what assumptions are most critical, and that monetary values are potentially significant.

86.0 Reference: Exhibit B-1-1, Appendix A-6, Pages 6 and 7

> In January the average temperature for Toronto is -6 °C. [8] An extended outage of natural gas can quickly make homes unlivable during the winter months to include the loss of water or water damage associated with the danger of freezing pipes. If an outage leads a small business to close its doors for more than 10 days, it may never fully recover financially. According to the *Insurance Institute for Business and Home Safety*, an estimated 25 percent of small businesses disrupted due to a disaster do not reopen. [9]
>
> While small businesses are important consumers of natural gas, Ontario is also home to many large energy-intensive businesses as well. These include major manufacturing plants that produce the province's leading international exports including motor vehicles and parts, mechanical equipment, and electrical machinery. [10] One key to Ontario's ability to sustain a projected growth in real exports at an average of 3 percent per year
>
> over the next two decades [11] will be that the province is able to maintain reliable access to relatively low-cost energy supplies. As such, natural gas will figure prominently in sustaining the competitive position of Ontario's major industries.

86.1 Please discuss whether or not FEI has accounted for the effect of small business shut down in the event of a worst case disruption event of significant duration.

Response:

HJ Ruitenbeek Resource Consulting Limited provides the following response:

The "service disruption" analysis in "Economic Consequence Analysis" Appendix A-5 reflects all losses to the residential and business components in the demand structure. The analysis does not explicitly single out "small businesses", but it does distinguish different values and impacts for different rate classes which would also reflect their potential coping strategies (including shutdown as one of those). The overall analysis also addresses long-term revenue losses to the utility because of lost customers, although it does not identify specifically what proportion of these would be small businesses.

86.2 Please discuss whether or not there is any critical export or economic dependence related issues, such as those referenced in Ontario, associated with the areas relevant for the potential disruption of service being examined.

Response:

FEI is not aware of any specific critical export or economic dependence related issues, such as those referenced in Ontario, associated with the areas relevant for the potential disruption of service being examined.

87.0 Reference: Exhibit B-1-1, Appendix A-6, Page 12

> **V. Conclusion:**
>
> In a world where disasters are becoming more frequent and intense, the competitive advantage will lie with those companies and communities that are best able to provide a continuity of critical services in the face of disruptive events. People will want to live and work, and investors will want to invest in places that are resilient. They will gravitate away from those locations that cannot provide essential needs in the face of known and unknown risks.
>
> Over the past century, North America generally and Ontario specifically has built an impressive track record of reliably meeting the economic and social needs of their citizens. This includes having the infrastructure in place to make affordable energy consistently available to heat and power homes and operate businesses. By bolstering the resilience of the Dawn-Parkway System, the proposed Parkway West Project will make a helpful contribution to continuing that tradition.

87.1 Please discuss Union Gas's enviable record of reliability and resiliency in comparison to FEI's record of reliability and resiliency and whether or not there are corporate and provincial implications for not maintaining such a record, in addition to customer implications.

Response:

FEI does not have access to any details with respect to Union Gas's record of reliability and resiliency; as a result, FEI is not in a position to compare FEI's record of reliability and resiliency with that of Union Gas.

With regard to potential implications and consequences of loss of service, FEI undertook the Economic Consequence Analysis included as Appendix A-5 to Exhibit B-1-1. The objective was to provide a quantitative estimate of the economic consequences of a significant outage. The assessment considered corporate, public and customer implications. The FEI Impact Chart (Figure B1 of Appendix A-5) is used as the basis for considering monetary impacts associated with a failure. On page 29 of Appendix A-5, the consequences included in the study are:

- Service Disruption Costs: Includes socio-economic costs associated with service disruption for an extended period of time
- Relight Costs: Includes costs associated with shut down, purging and relighting customers impacted by an outage

- Loss of Revenue Costs: Includes loss of revenue costs associated with service interruption for all customers during the event, and for an extended period of time for a percentage of the customers.
- Regulatory Response Costs: Evaluates anticipated regulatory response costs associated with a failure, and subsequent major service outage
- Public Opinion Costs: Evaluates anticipated public opinion costs associated with a failure, an subsequent major service outage
- End Use Customer Loyalty Costs: Evaluates anticipated customer loyalty costs associated with a failure, and subsequent major service outage
- Government Relations Costs: Evaluates anticipated government relations costs associated with a failure, and subsequent major service outage.

The Projects as proposed will provide full resiliency and continued reliable gas service to Metro IP customers even in the event of a significant unplanned event that would otherwise result in a large number of customer outages and resulting economic consequences to customers, the public and the Company.

88.0 Reference: Exhibit B-1-1, Appendix A-7-1, Page 2

> The National Strategy is based on the recognition that enhancing the resiliency of critical infrastructure can be achieved through the appropriate combination of security measures to address intentional and accidental incidents, business continuity practices to deal with disruptions and ensure the continuation of essential services, and emergency management planning to ensure adequate response procedures are in place to deal with unforeseen disruptions and natural disasters.

88.1 Please discuss any implications FEI perceives may be connected to the resiliency of critical infrastructure that would flow into a National context, if any.

Response:

The National Strategy for Critical Infrastructure (see page 2 of Appendix A-7-1) considers energy and utilities to be critical infrastructure sectors for Canada. FEI falls within those sectors. Projects undertaken by FEI to improve the resiliency of its infrastructure would support the National Strategy. As described in the Executive Summary:

> *The National Strategy supports the principle that critical infrastructure roles and activities should be carried out in a responsible manner at all levels of society in Canada. Responsibilities for critical infrastructure in Canada are shared by federal, provincial and territorial governments, local authorities and critical infrastructure owners and operators – who bear the primary responsibility for protecting their assets and services.*

Please also refer to the response to CEC IR.1.89.1.

89.0 Reference: Exhibit B-1-1, Appendix A-8, Pages 3 and 4

Critical infrastructure owners/ operators	Collaboratively manage risks related to their critical infrastructure	• Manage risks to their own critical infrastructure • Participate in critical infrastructure identification, assessment, prevention, mitigation, preparedness, response and recovery activities

> The enormity and complexity of critical infrastructure, the interdependencies that cross sectors and jurisdictions, and the uncertain nature of risks and natural disasters make the effective implementation of protection efforts a great challenge. The coordination mechanisms described below establish linkages among federal, provincial and territorial governments and critical infrastructure sectors. They will all be invited to participate in the sector networks and will be represented at the National Cross-Sector Forum. In addition to direct coordination between critical infrastructure partners, the structures described below provide a national framework that fosters relationships and improves information sharing and risk management within and across critical infrastructure sectors.

89.1 Please discuss the importance of critical infrastructure owners and operators managing their own risks to their own critical infrastructure, in the context of national, provincial and municipal cooperation and partnership building and whether or not there is relevance for FEI in the LMIPSU Project as part of its overall resiliency responsibilities.

Response:

The National Strategy for Critical Infrastructure for Canada (refer to Appendix A-7-1, page 2), describes Critical Infrastructure as follows:

"Critical infrastructure refers to processes, systems, facilities, technologies, networks, assets and services essential to the health, safety, security or economic well-being of Canadians and the effective functioning of government. Critical infrastructure can be stand-alone or interconnected and interdependent within and across provinces, territories and national borders. Disruptions of critical infrastructure could result in catastrophic loss of life, adverse economic effects, and significant harm to public confidence".

The National Strategy for Critical Infrastructure further states that:

"The National Strategy supports the principle that critical infrastructure roles and activities should be carried out in a responsible manner at all levels of society in Canada. Responsibilities for critical infrastructure in Canada are shared by federal, provincial and territorial governments, local authorities and critical infrastructure owners and operators – who bear the primary responsibility for protecting their assets and services. Individual

> *Canadians also have a responsibility to be prepared for a disruption and to ensure that they and their families are ready to cope for at least the first 72 hours of an emergency.*
>
> *Given that disasters most often occur locally, the National Strategy recognizes that, in an emergency, the first response is almost always by the owners and operators, the municipality or at the provincial/territorial level. The federal government fulfils national leadership responsibilities relating to emergency management, respecting existing federal, provincial and territorial jurisdiction and legislation. The federal government is also responsible for providing assistance to provinces/territories if the province/territory has requested the assistance."*

The Coquitlam Gate IP pipeline and the Fraser Gate IP pipeline together serve in excess of 210,000 customers in a geographical area that has a population in excess of 1 million people. FEI, as the owner and operator of these pipelines, has determined that under the existing conditions, a failure of either of these pipelines could have an adverse economic effect and significant harm to public confidence in the energy infrastructure.

The Projects will result in a more reliable and resilient system that will significantly reduce the probability of such an event. FEI believes that the construction of a resilient infrastructure in the Metro Vancouver area is consistent with the intent of National Strategy for Critical Infrastructure.

90.0 Reference: Exhibit B-1-1, Appendix A-10, Page 10

> Based on the analysis described above, the normalized failure frequency value derived from an analysis of the PHMSA Gas Transmission Incident Database (i.e., FF_{PHMSA} in Equation 2) was determined to be 4.106x10^{-04} failures/km.yr. This number is derived from combining a failure rate of 9.364x10^{-05} failures/km.yr from incidents occurring on operator-controlled property, with 3.170x10^{-04} failures/km.yr occurring on right-of-way. All of these failures represent loss of containment incidents that are of sufficient magnitude that they would be likely to result in a loss of service. For all pipeline segments, with the exception of those segments in which there exists

90.1 Please discuss whether or not the failure incidents recorded in the PHMSA database had loss of service or only could likely have resulted in a loss of service and if so identify the number that resulted in a loss of service shut down.

Response:

DRAS provides the following response:

The term 'loss of service' is not used in the PHMSA incident database. Instead, only 'shutdown' is reported. The term 'shutdown' has a definition that is distinct from 'loss of service'. The term 'shutdown' is used in the PHMSA incident database to denote that a segment of pipeline has been taken out of service for a period of time. While loss of service (one or more customers who lose service as a result of the incident) may or may not occur even if an incident does not result in a shutdown, loss of service is not recorded in the PHMSA incident database.

As indicated in Appendix A-10, the PHMSA incident database was utilized to provide a basis for estimating the frequency of leaks of sufficient magnitude that could result in a loss of service. As discussed in that document, various filters were applied to the PHMSA incident database in order to generate a list of incidents from which this estimate could be obtained. A review of the metadata associated with these incidents revealed that shut-down occurred in 68% of the cases. The remainder of the incidents were associated with circumstances that fell into one of two categories, as follows:

i) The incident occurred in a station in which isolation could occur while maintaining service due to valve and piping configuration in the station; or,

ii) The incident occurred in a pipe segment that was configured such that isolation could occur without causing loss of service.

The feasibility of preventing loss of service by means of isolation is highly-dependent on system configuration and system loads at the time of the incident, and the maintenance of service after isolation is dependent on the ability of sustaining loads by feeding through alternative infrastructure. In the absence of availability of such alternative infrastructure to maintain loads, loss of service will occur.

90.2 Please discuss whether or not the failure incidents recorded in the PHMSA had recovery times for service in the range of 25 days maximum and if so how many had such lengthy recovery times.

<u>Response:</u>

DRAS has provided the following response:

A review of the metadata associated with the PHMSA incident data cited in the response to CEC IR 1.90.1 indicated that where shutdown occurred, the shutdown period exceeded 15 days 7% of the time. It should be noted that where significant numbers of relights are required, even very short pipeline repair periods can result in extensive shutdown periods.

FEI further adds the following comment:

The duration of the recovery time is dependent on the system configuration (resiliency), numbers of customers, and loads. If a failure occurs on a system without resiliency then customer interruptions will occur and the recovery time will depend of the number of customers impacted. If a failure occurs on a system with resiliency then no customer interruptions will occur. It is irrelevant what the recovery time is for each failure incident in the PHMSA database as it is the potential impact of a failure of this magnitude on the FEI system where it lacks sufficient resiliency that is important.

90.3 Please discuss the criteria of sufficient magnitude that would likely result in a loss of service in terms of the quantity of loss and please identify the number of the total of these which did not result in a loss of service.

<u>Response:</u>

DRAS provides the following response:

DRAS is not entirely clear on the information that is being requested. Nevertheless, for the purposes of attempting to be responsive to the information request, it is being assumed that this request pertains to the criteria that were applied to the PHMSA incident data to identify those incidents that have the potential to result in a loss of service. Those criteria are described in detail in Section 3.1 of Appendix A-10. A summary of the findings from a review of the metadata associated with those incidents was provided in the response to CEC IR 1.90.1.

90.4 Please identify any incidents in the FEI system in which such quantity of loss as was used for the criteria for selecting PHMSA data has been experienced but loss of service was not required.

Response:

DRAS provides the following response:

As described in Section 3.1 of Appendix A-10, the PHMSA incident database was utilized to provide a basis for estimating the frequency of leaks of sufficient magnitude that could result in a loss of service. As discussed in that document, various filters were applied to the PHMSA incident database in order to generate a list of incidents from which this estimate could be obtained. Therefore, the criteria that were applied to the PHMSA incident database to identify where loss of service could occur were evidence-based (e.g., the criteria involved looking for evidence that a loss of service did, or could have occurred).

Based on the analysis of PHMSA incident data, the frequency of occurrence of these incidents was established as 4.1×10^{-04} /km·yr. In other words, the PHMSA incident data analysis would suggest that a 10-km long segment of pipeline would incur such an incident on average once every 240 years. As such, these incidents within the infrastructure of any individual operator are comparatively rare.

FEI further adds the following comments:

The feasibility of preventing loss of service by means of isolation is highly-dependent on system configuration and system loads at the time of the incident, and the ability to maintain service after isolation is dependent on the ability to sustain loads by supply through alternative infrastructure. In the absence of availability of such alternative infrastructure to maintain loads, loss of service will occur. Please also refer to the response to CEC IR 1.90.1.

90.5 Please confirm that these probabilities of failures represent probabilities throughout the year but that the maximum number of customers affected in the FEI system is restricted to a cold weather time of year and would be fewer customers potentially affected at other times of year.

Response:

DRAS provides the following response:

Confirmed. The event frequencies represent the frequency of leaks of sufficient magnitude that could result in a loss of service, while the impacts are those associated with design conditions. Therefore, as outlined in Appendix A-10, the differential Loss of Service risk represents the risk differential under a reasonable worst case scenario.

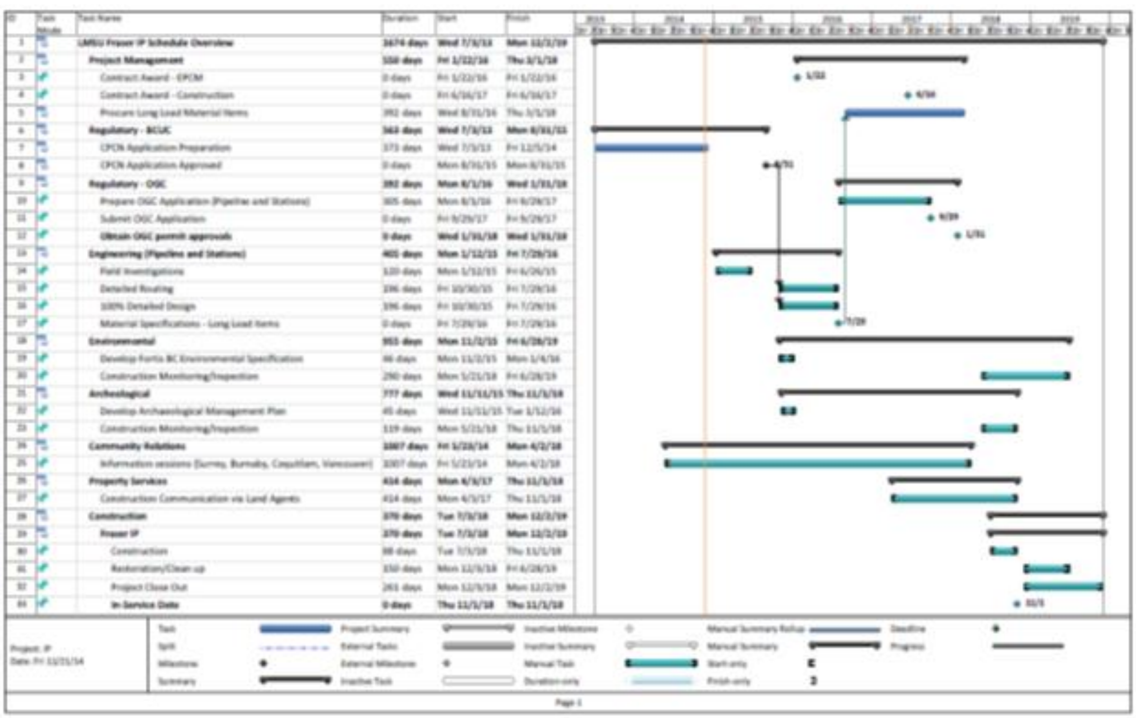
90.6 Please confirm that the probability of failure at a specific time of year would be the joint probability of the failure of the pipe and the probability that it occurred at the specific time of year.

Response:

DRAS provides the following response:

The probability of failure under design conditions is the joint probability of: [the probability of failure] and [the probability of operating under design conditions]. No seasonal variation in failure frequency is assumed within the risk assessment. As stated in Appendix A-10, the analysis was conducted under design conditions to represent a reasonable worst case scenario.

91.0 Reference: Exhibit B-1-1, Appendix A-20-1 and Appendix A-20-2



91.1 Please discuss why community relations would not carry on through to the end of construction and other highly visible and interactive (with impact in the community) stages of the project.

Response:

Community Relations will indeed carry on through to the end of construction and beyond if needed. The Project schedules referred to above represent only one aspect of Community Relations, which is public information sessions.

92.0 Reference: Exhibit B-1-1, Appendix C-1, Page 3

- Province-wide issues:
  - Debate and public perception around pipelines, such as Northern Gateway and Kinder Morgan, two proposed exporting pipeline projects
  - LNG debate
  - Natural gas vs. municipal carbon reduction targets
  - Municipal election year

92.1 Would it make sense to reference natural gas, province wide issues, to the BC GHG reduction target legislation as well as to municipal carbon reduction targets?

Response:

FEI believes the Projects are fundamentally about maintaining safe and reliable service of the existing gas supply into the Metro IP system. However, the Company looked toward municipal governments' input to and support of these Projects and was mindful of municipal goals to reduce carbon emissions as well as other Provincial-wide issues such as anti-pipeline campaigns, the election landscape, and GHG emissions targets. Therefore, FEI's messaging took into account the public policy debates and reinforced the fact that the Projects would not increase GHG emissions in Metro Vancouver communities.

93.0 Reference: Exhibit B-1-1, Appendix C-1, Page 6

29 • Reinforcing FEI's position as a leading energy provider

93.1 Would it make more sense to reinforce FEI's position as a leading energy provider of safe and reliable natural gas energy service?

Response:

Confirmed. The phrase "providing safe and reliable energy, including natural gas" is the opening line in the mission statement for FortisBC Energy Inc. The statement referenced in Exhibit B-1-1, Appendix C-1, Page 6 is an edited version of the mission statement, which is appended in its entirety below.

FortisBC is a regulated utility focused on providing safe and reliable energy, including natural gas, electricity and propane. FortisBC employs more than 2,200 British Columbians and serves approximately 1.1 million customers in 135 B.C. communities. FortisBC owns and operates two liquefied natural gas storage facilities and four regulated hydroelectric generating plants, approximately 7,150 kilometres of transmission and distribution power lines, and approximately 46,000 kilometres of natural gas transmission and distribution pipelines. FortisBC Inc. and FortisBC Energy Inc. do business as FortisBC. FortisBC is indirectly, wholly owned by Fortis Inc., a leader in the North American electric and gas utility business. Fortis Inc. shares are listed on the Toronto Stock Exchange and trade under the symbol FTS. Additional information can be accessed at www.fortisinc.com or www.sedar.com.

94.0 Exhibit B-1, Page 137

Details of the Coquitlam Gate IP Project capital costs can be found in Confidential Appendix E-1-1, Schedule 6, and in Confidential Appendix E-3-1. Fraser Gate IP Project costs can be found in Confidential Appendix E-1-2, Schedule 6, and in Confidential Appendix E-3-2.

Based on the Projects' costs, Table 5-1 presents a summary of the total forecast project costs and Table 5-2 presents the financial impacts associated with the completion of each of the two IP pipeline Projects as well as a summary of the combined rate impacts. Both tables are based on detailed schedules for each pipeline segment as included in Confidential Appendices E-1-1 and E-1-2. The impact to customer rates in 2019 (when the asset enters rate base) is approximately $0.130 per GJ and levelized over the 60 year analysis period is approximately $0.108 per GJ. For a typical FEI residential customer consuming an average 95 GJ per year, in 2019, this would equate to approximately $12.35 per year. The annual impact to customers from the Coquitlam Gate IP Project in 2019 would be approximately $11.60 per year and from the Fraser Gate IP Project would be approximately $0.75 per year.

Table 5-1: Summary of Forecast Capital and Deferred Costs ($millions)

Particular	2014$	As-Spent	AFUDC	Tax Offset	Total
Coquitlam Gate IP Project	201.282	228.813	12.455		**241.268**
Fraser Gate IP Project	14.855	17.231	0.876		**18.107**
Total Addition to Plant	216.137	246.044	13.331		**259.375**
Abandonment/Demolition Costs[28]	3.540	4.172	0.117		**4.289**
Total Projects Capital Cost	219.677	250.216	13.448		**263.664**
LMIPSU Development Cost	2.441	2.442	0.197	(0.635)	**2.004**
LMIPSU Application Cost	1.307	1.307	0.080	(0.340)	**1.047**
Total	**223.425**	**253.965**	**13.725**	**(0.975)**	**266.715**

94.1 Please provide the annual impact to each class of Commercial customers from each project in 2019.

Response:

Based on the approved commodity and common delivery rates effective January 1, 2015, the approximate annual bill impact for small commercial customers is estimated to be approximately 1.4% and 0.1% from the Coquitlam Gate IP Project and the Fraser Gate IP Project respectively. For large commercial sales customers the approximate annual bill impact is estimated to be approximately 1.6% and 0.1% from the Coquitlam Gate IP Project and the Fraser Gate IP Project respectively. Due to their individual commodity arrangments, FEI cannot provide a comparable estimated annual bill impact for Transportation customers; however, it is reasonable to expect that these customers would have an annual bill impact similar to large commercial sales customers.

The sum of the results from the Coquitlam IP Project and the Fraser Gate IP Project is the same as in FEI's response to CEC IR 1.7.1.

Attachment 9.3

BC Oil & Gas COMMISSION

December 18, 2013 Enforcement File: 13-96

Fortis BC Energy Inc.
16705 Fraser Highway
Surrey, BC, V4N 0E8
Attention: Keith Recsky, Sr. Integrity Engineer

Re: General Order 2013-25

Dear Mr. Recsky

The Commission has received and reviewed Fortis BC's response to General Order 2013-25, thank you. Though not a requirement identified on the order, the Commission would appreciate receiving monthly submissions from Fortis BC detailing the weekly leak detection surveys being completed. Please submit the reports electronically to Kevin.Parsonage@bcogc.ca.

Additionally, would you please contact Kevin Parsonage, Supervisor, Field Engineering & Technical Investigations to discuss the proposed date Fortis BC intends to submit an application to the Commission for the pipeline replacement.

Thanking you in advance.

Yours Truly,

Keith Rande
Manager Enforcement
Oil and Gas Commission

cc. Dean Zimmer, Director C&E, OGC
Jason Wilson, Pipeline Engineer, OGC

Enforcement Section
6534 Airport Rd.
Fort St. John BC V1J 4M6
Telephone 250-794-5309
24 hour 250-794-5200
Fax 250-794-5389

Attachment 21.3

FILED CONFIDENTIALLY

Attachment 83.7

Economics of Condensing Gas Furnaces and Water Heaters Potential in Residential Single Family Homes

Alex Lekov, Victor Franco, and Steve Meyers, Lawrence Berkeley National Laboratory

ABSTRACT

Residential space and water heating accounts for over 90% of total residential primary gas consumption in the United States. Condensing space and water heating equipment are 10-30% more energy-efficient than conventional space and water heating. Currently, condensing gas furnaces represent 40 percent of shipments and are common in the Northern U.S. market. Meanwhile, manufacturers are planning to develop condensing gas storage water heaters to qualify for Energy Star® certification. Consumers, installers, and builders who make decisions about installing space and water heating equipment generally do not perform an analysis to assess the economic impacts of different combinations and efficiencies of space and water heating equipment. Thus, equipment is often installed without taking into consideration the potential life-cycle economic and energy savings of installing space and water heating equipment combinations. Drawing on previous and current analysis conducted for the United States Department of Energy rulemaking on amended standards for furnaces and water heaters, this paper evaluates the extent to which condensing equipment can provide life-cycle cost-effectiveness in a representative sample of single family American homes. The economic analyses indicate that significant energy savings and consumer benefits may result from large-scale introduction of condensing water heaters combined with condensing furnaces in U.S. residential single-family housing, particularly in the Northern region. The analyses also shows that important benefits may be overlooked when policy analysts evaluate the impact of space and water heating equipment separately.

Introduction

Residential space and water heating accounts for 39% of total residential primary energy consumption and 94% of all residential gas[1] consumption in the United States (4.6 quads in 2009). (USDOE 2010a) A gas furnace and a gas water heater is the most common combination of space and water heating equipment in existing single-family homes and on average about half of all new single-family homes are installed with this combination (USDOC BOC 2010a; USDOC-BOC 2010b).

In the replacement market for single-family homes, the homeowner and contractor are primarily responsible for the selection of space and water heating equipment. Yet a large fraction of furnace and water heater replacements are done on an emergency basis. In new single-family construction, the builder is primarily responsible for the selection of space and water heating equipment (Ashdown et al. 2004).

This study applies a life-cycle cost (LCC) analysis[2] to calculate the economic advantages and disadvantages to consumers of several alternative gas furnace and water heater combinations installed in single-family homes. In the past, the U.S. Department of Energy (DOE) has

[1] Includes both natural gas and liquid petroleum gas (LPG).
[2] An LCC analysis is a cost/benefit analysis over the lifetime of the equipment from a consumer perspective.

performed separate LCC analysis on residential furnaces and on water heaters (Lekov et al. 2006; Lekov 2000). This paper expands on a gas furnace and water heater study (Lekov et al. 2009) that assessed the economics of gas space and water heating equipment combinations in the new single-family construction market to look at the replacement market in single-family homes. It updates the new construction results with updated data using the recently published USDOE 2010 water heating rulemaking. (USDOE 2010b)

U.S. Gas Space and Water Heating Market and Technology Characterization

Central heating systems (air distribution and hydronics) in the United States account for 82% of residential heating equipment stock in 2005 (USDOE 2005) and 98% of all single family new construction built from 1997-2008 (USDOC-BOC 2010b). The U.S. central space heating market is dominated by forced air furnaces which account for 85% of the stock and 97% of all single family new constructions built during 1997-2008. The current stock of residential water heating equipment is predominantly storage water heaters. Regionally, gas-fired water heating is dominant in all regions except in the South.

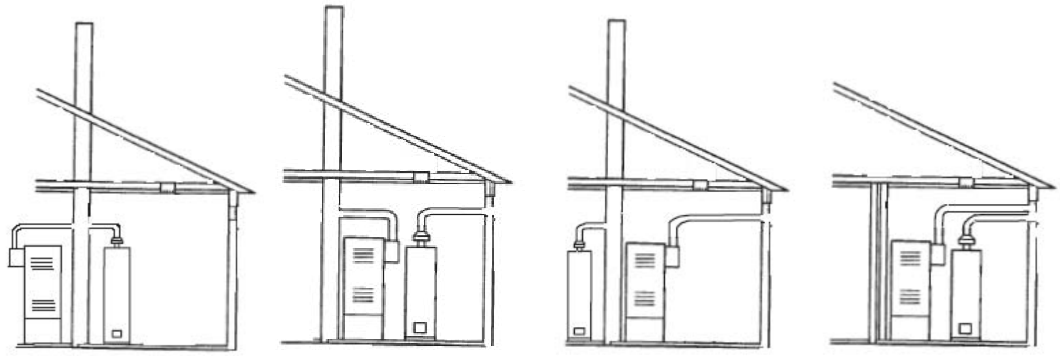
Gas furnaces and water heaters are often distinguished by whether they use condensing or non-condensing technology. A typical non-condensing gas furnace (NCGF) has an efficiency rating of about 80 percent annual fuel utilization efficiency (AFUE), while a condensing gas furnace (CGF) has an efficiency rating at or above 90-percent AFUE. In 2008, the most common furnace installed for replacement and in new construction was a non-condensing gas furnace (approximately 56%) (AHRI 2010a).

The efficiency of water heaters, depending on the rated volume and other design considerations, ranges from 0.50 to 0.63 energy factor (EF) for Non-Condensing Water Heaters (NCWH). Currently, nearly all gas water heaters installed are non-condensing. There are currently no shipments of residential condensing water heaters (CWH)[3], but there are prototype models available and condensing water heaters are included in the current Energy Star® water heater program (USEPA 2008).

The venting installation requirements are different for the various furnace and water heater designs. Figure 1 illustrates typical venting configurations. Identifying venting configurations is important because the venting system represents a significant fraction of the total installed cost and differs significantly for different furnace and water heater combinations. For new construction, configuration (d) is the least expensive, since it uses plastic venting materials and shorter vent lengths. Configuration (a) uses a single vent system for both appliances and is the most common venting configuration. Configurations (b) and (c) are the most expensive because of the need to apply two different venting types.

[3] There are some "non-residential" condensing models that are being used in residential applications (e.g., A.O. Smith's Vertex models)

Figure 1. Four Gas Furnace and Gas Water Heater Venting Configurations



(a) gas furnace and water heater vented through the roof; (b) gas furnace vented through the roof and gas water heater vented through the sidewall; (c) gas furnace vented through the sidewall and gas water heater vented through the roof; and (d) gas furnace and gas water heater vented through the sidewall

Methodology

This study assessed the energy savings and economics of the selected water heater and furnace configurations when they are installed single family homes. The LCC analysis addressed both the cost of buying and installing a furnace or water heater, and the operating costs summed over the lifetime of the equipment, discounted to the present.

To account for the uncertainty and variability of the inputs to the LCC analysis, Monte Carlo[4] simulations were applied, with many of the variables used in the calculations (e.g., discount rate, energy prices, equipment lifetime) represented as distributions of values and with probabilities (weighting) attached to each value (Lutz et al. 2000). The LCC analysis estimated furnace and water heater energy consumption under field conditions for a sample of households selected from the 2005 Residential Energy Consumption Survey (RECS 2005) (USDOE 2005). The sample was derived from single-family households in RECS 2005 that had both a gas furnace and gas storage water heater. This study focuses on non-weatherized gas furnaces, but since RECS does not specify the type of gas furnace, the sample weighting was adjusted. Since weatherized gas furnaces[5] are installed mostly in the South, the RECS weight was decreased for all households in the South by 25%.[6] For new construction, the sample was derived by selecting only single-family households built after 1980[7] and adjusting the regional weights by the using the most current new housing characteristics data from the U.S. Census. (USDOC-BOC 2010b)

Table 1 shows the four gas furnace and water heating options considered in this analysis. The efficiency values used in the calculations were based on commonly available models (USDOE 2007; USDOE 2010b). Option 1 (NCGF/NCWH) represents the least efficient furnace and water heater combination and Option 4 (CGF/CWH) represents the most efficient

[4] The Monte Carlo method uses computational algorithms that rely on repeated random sampling to compute results. In this study, the Monte Carlo analysis is performed using Crystal Ball, add-on software to MS Excel. The results are based on 10,000 samples per Monte Carlo simulation run.

[5] Also known as gas package heating/cooling units

[6] Weatherized gas furnaces account for approximately 11% of gas furnace shipments. These furnaces are all assumed to be in the south, so the 11% share of gas furnace implies that 25% of homes with gas furnace in the South have a weatherized gas furnace. The weight of all RECS households in the South are decreased to approximate the effect of removing households from the sample.

[7] Households built after 1980 was selected in order to have a large enough sample size.

combination. The fact that Option 4 (CGF/CWH) uses venting configuration (d) is significant, since this configuration is the least expensive one for new construction and could be beneficial in some replacement installations.

For the replacements, several scenarios are possible: furnace and water heater are replaced at the same time, furnace is replaced first, or water heater is replaced first. For simplicity and because the condensing furnace market is increasing and holds a significant market share, for this study the furnace is assumed to be replaced first. In **Table 1**, Options 1 and 3 represent the cases where the homeowner replaces the furnace, but the water heater is replaced once it fails in the future). The failure year of the water heater after the furnace is replaced is calculated by taking into account the existing equipment age from RECS 2005 of the water heater and the lifetime distribution. For Options 2 and 4, which include a condensing water heater, both pieces of equipment are replaced at the same time (either because they failed at same time or early replacement of water heater is chosen). The remaining value of the existing water heater is accounted for by annualizing the total installed cost of the existing water heater and applying this cost for the remaining useful lifetime. This cost varies among the sample households depending on the age of the water heater.

Table 1. Gas Furnace and Gas Water Heater Options

Option		Furnace Type	Gas Water Heater Type[a]	Venting Configuration
1	NCGF/NCWH	Non-condensing (80% AFUE)	Non-Condensing (0.59 EF)	Configuration (a)
2	NCGF/CWH		Condensing (0.78 EF)	Configuration (b)
3	CGF/NCWH	Condensing (90%AFUE)	Non-Condensing (0.59 EF)	Configuration (c)
4	CGF/CWH		Condensing (0.78 EF)	Configuration (d)

[a] Water heater efficiency at 40 gallon rated volume. Condensing water heater efficiency is based on manufacturer measurements of a prototype model. The current Energy Star® efficiency requirement for condensing water heaters is 0.80 EF.

To calculate the relative advantages and disadvantages of an option, the life-cycle cost savings and the pay-back period (PBP) are assessed by comparing Option 1, which is the most common, to higher efficiency options (2-4).

In addition to a national LCC analysis, a regional LCC analysis is performed for Northern states (above 5000 HDD) and Southern states (below 5000 HDD) (USDOC-BOC 2009). The regional analysis accounts for significant energy use variations due to climate conditions (particularly for furnaces) as well as for regional differences in household characteristics, energy prices, and other parameters.

The analysis considered the period from initial furnace and water heater installation to the end of the lifetime of the furnace. Given the lifetime distributions for the water heater and the furnace, most of the time one or more additional water heater(s) would be installed during the lifetime of the furnace. In these cases, the total installed cost of the replacement water heater was added to the operating cost as an annualized expense from the time of the replacement to the end of the furnace lifetime.

LCC and PBP Analysis

The total installed cost includes the consumer cost and the installation cost, which includes labor, overhead, and any miscellaneous materials and parts. The operating cost includes the energy expenditures and the repair and maintenance costs as well as the annualized cost of a replacement water heater. Each of these inputs is discussed below.

Consumer product cost. Consumer product costs are based on U.S. DOE research that derived the consumer cost based on manufacturer cost and contractor/builder and distributor markups for gas furnaces (USDOE 2007) and the gas water heaters (USDOE 2010b).[8] Manufacturer costs of a condensing furnace include the additional secondary heat exchanger cost. The manufacturer cost of a condensing water heater includes the cost of changes to the heat exchanger and the tank. The analysis applies markups to transform the manufacturer costs into a consumer cost.[9]

Table 2 shows the average consumer costs for the furnaces and water heaters used in the LCC analysis. The prices are higher for new construction because DOE applies a builder markup. The given prices are based on manufacturer costs that assume a high level of production of these products and reflect economies of scale in production that are not yet being captured in the current condensing water heater market. For comparison, the current retail price for a commercial condensing water heater which has characteristics similar to the residential water heater is $1,600.[10] Based on this model (which has a higher input capacity than an equivalent residential model), the cost for a comparable residential model should be lower due to the smaller burner required for residential designs. Tax credits that are available for gas condensing furnaces and water heaters purchased by Dec. 31, 2010 or state and utility rebates are not included.

Table 2. Average Consumer Product Cost for Gas Furnace and Gas Water Heater Options

Options	Gas Furnace (2009$)		Gas Water Heater (2009$)		Total (2009$)	
	New Home	Replacement	New Home	Replacement	New Home	Replacement
NCGF/NCWH	$1,481	$1,182	$515	$448	$1,997	$1,629
NCGF/CWH	$1,481	$1,182	$1,126	$1,052	$2,608	$2,234
CGF/NCWH	$1,956	$1,599	$515	$448	$2,472	$2,046
CGF/CWH	$1,956	$1,599	$1,126	$1,052	$3,083	$2,651

Installation cost. The installation costs for each of the options shown in **Table 3** come from US DOE research based on RSMeans cost estimates (USDOE 2010b). The installation cost includes labor and materials for the gas furnace and water heater. The basic installation includes adding a gas line branch, water piping, and condensate drain for water heaters and air-distribution connections and electrical components for furnaces, as well as the cost of locating and setting up the units. The main difference in installation cost between condensing and non-condensing equipment is the difference in cost of exhausting the condensate flue gases via a horizontal plastic vent compared to exhausting them via a vertical metal vent. Three different vent systems are considered: Option 1 uses a common vent through the roof; Options 2 and 3 use a combination of vertical metal vent and horizontal plastic vent; and Option 4 uses plastic vent. (See Figure 1).

[8] DOE research used a reverse-engineering approach to obtain manufacturers' costs.
[9] The overall markup approach is explained in US DOE Heating Products Rulemaking TSD (USDOE 2010b).
[10] Based on AO Smiths Vertex condensing water heater at 76 kBtu/h (http://www.pexsupply.com/AO-Smith-GPHE-50-50-Gallon-76000-BTU-Vertex-Power-Vent-Residential-Gas-Water-Heater)

Table 3. Installation Costs for Furnace and Water Heater Options (2009$)

Option	Venting Installation Configuration	New Construction			Replacement		
		Furnace	Water Heater	Total	Furnace	Water Heater	Total
NCGF/NCWH	Configuration A	$992	$945	$1,936	$784	$583	$1,246
NCGF/CWH	Configuration B	$1,281	$658	$1,939	$784	$1,036	$1,820
CGF/NCWH	Configuration C	$685	$1,234	$1,918	$942	$583	$1,425
CGF/CWH	Configuration D	$500	$623	$1,123	$778	$1,001	$1,780

Heating load and hot water use. Energy consumption for both the furnace and the water heater is based on calculations that use DOE test procedures while varying certain input parameters (Lutz et al. 1999; Lutz et al. 2004). The house heating load (for furnaces) and the hot water use (for water heaters) used in the calculations vary for each sample household. **Table 4** shows the house heating load and hot water use average and median values for the household sample by region. The national average hot water use (45.7 gal) is lower than the average value for gas water heaters (64.2 gal) in the DOE test procedure for water heaters.

Table 4. Average House Heating Load and Hot Water Use by Region

	Units	Northern Region				Southern Region	National
		Northeast	Midwest	Northwest	Total		
House Heating Load	MMBtu/y	49.0	48.1	39.5	48.1	28.8	39.4
Hot Water Use	gal/day	46.6	42.6	46.4	43.9	48.8	45.7

Operating costs. The operating costs represent the costs paid by the consumer to operate and maintain or repair the furnace and the water heater over the lifetime of the equipment. The operating cost uses energy consumption and energy prices as inputs. Average monthly energy prices are determined separately for the nine Census divisions and four large states based on 2008 EIA data, historical monthly EIA data, and 2008 U.S. Census Bureau population estimates (USDOE 2010c; USDOE 2010d; USDOE 2010e; USDOC-BOC 2010c). The derived energy prices are matched to each individual household depending on its location. To arrive at prices in future years, 2008 average prices are multiplied by the forecast of annual average price changes in AEO2010 (Early Release) (USDOE 2010a).

The furnace maintenance cost accounts for regular maintenance every five years, while the maintenance cost for water heaters includes maintenance for draining the tank and checking the flammable vapor ignition resistant (FVIR) system. The analysis assumes that certain components of both furnaces and water heaters might be repaired during the lifetime of the equipment (e.g. ignition device, blower motor, and power vent) (USDOE 2010b).[11] **Table 5** lists the repair cost of key components as used in the analysis.

[11] In the LCC analysis both the lifetime of the equipment and the component lifetime are presented as distributions. Therefore only households that have relatively longer equipment lifetime encounter repair costs.

Table 5. Gas Furnace and Gas Water Heater Component Repair Cost and Lifetime

	Component	Lifetime	Repair Cost (2009$)	Applied to Option
Gas Furnace	Electronic Ignition	10	$204	1,2,3,4
	Blower Motor	12	$297	1,2,3,4
	Inducer Motor	15	$297	1,2,3,4
Gas Water Heater	Pilot Light Ignition	10	$162	1,3
	Electronic Ignition	15	$204	2,4
	Power Vent	15	$297	2,4

Discount rate. The LCC analysis discounted future operating costs to 2010 and summed them over the lifetime of the furnace. For new construction, the discount rate used reflects after-tax real mortgage rates and on average equals 3.0%, while for the replacement market, the discount rate averages 5.1% (USDOE 2010b).

Lifetime. Lifetime estimates for furnaces and water heaters are shown in Table 6 (USDOE 2007; USDOE 2010b). In the analysis, lifetime is represented as a Weibull distribution. The analysis uses the same lifetime for all furnace and water heater designs.

Table 6. Furnace and Water Heater Lifetime

Product Class	Minimum	Average	Maximum
Gas Water Heater	6	13	30
Gas Furnace	10	20	30

Results

The life-cycle cost savings for the national sample compared to purchase and use of the baseline non-condensing furnace and water heater and the pay-back period of each considered option in the case of replacement and new construction are shown in **Table 7**. The share of households with net LCC benefit and with net LCC cost is also shown in **Table 7**. (Note: 15-20% of furnace and water heater shipments are for new construction.) In replacement cases, the condensing gas furnace provides positive LCC savings and a reasonable PBP when paired with a non-condensing water heater, but on average the condensing water heater does not provide savings in either of the considered combinations. In new construction, combining a condensing gas furnace with a condensing water heater is the most attractive option, providing a net benefit to three-fourths of the households in the new construction sample.

Results for the North and South household samples are shown in **Tables 8** and **9**, respectively. In the North, the pattern of results is roughly the same as with the national sample for new construction. However, in this region the condensing gas furnace plus condensing water heater option has a slightly positive LCC savings for replacement situations. Over half of the sample households have a net cost. In the South, the condensing gas furnace plus condensing water heater option are attractive in new construction, but none of the options have a positive average LCC savings in the replacement sample. Regional results are shown in **Figure 2**.

Results for the condensing gas furnace plus condensing water heater option vary among parts of the North region as shown in **Table 10**. The differences are due mostly to variation in energy prices and energy use.

Table 7. National LCC and PBP Results for Replacement and New Construction Cases

Option	Life-Cycle Cost *(2009$)*			Life-Cycle Cost Savings			Payback Period[12]	
	Average Installed Price	Average Lifetime Operating Cost*	Average LCC	Average Savings *(2009$)*	Households with Net Cost	Households with Net Benefit	Mean *(years)*	Average *(years)*
REPLACEMENT								
NCGF/NCWH	$2,875	$14,164	$17,038					
NCGF/CWH	$4,054	$13,799	$17,853	-$815	94%	6%	35	55
CGF/NCWH	$3,471	$13,179	$16,650	$389	42%	59%	9.7	17
CGF/CWH	$4,431	$12,814	$17,245	-$206	66%	34%	15.8	22.2
NEW CONSTRUCTION								
NCGF/NCWH	$3,933	$16,226	$20,159					
NCGF/CWH	$4,546	$15,859	$20,406	-$247	69%	31%	21	34
CGF/NCWH	$4,390	$15,111	$19,501	$658	26%	74%	8.1	12
CGF/CWH	$4,206	$14,745	$18,951	$1,208	14%	86%	3.5	5.9

* Discounted

Table 8. LCC and PBP Results for Replacement and New Construction Cases (NORTH)

Option	Life-Cycle Cost *(2009$)*			Life-Cycle Cost Savings			Payback Period	
	Average Installed Price	Average Lifetime Operating Cost*	Average LCC	Average Savings *(2009$)*	Households with Net Cost	Households with Net Benefit	Mean *(years)*	Average *(years)*
REPLACEMENT								
NCGF/NCWH	$3,027	$16,549	$19,576					
NCGF/CWH	$4,271	$16,169	$20,440	-$864	94%	6%	35	54
CGF/NCWH	$3,584	$15,311	$18,896	$680	23%	77%	6.6	8.2
CGF/CWH	$4,565	$14,931	$19,496	$80	56%	44%	12.8	14.3
NEW CONSTRUCTION								
NCGF/NCWH	$4,060	$18,988	$23,046					
NCGF/CWH	$4,730	$18,601	$23,329	-$283	71%	29%	22	35
CGF/NCWH	$4,575	$17,584	$22,157	$889	16%	84%	7.6	7.9
CGF/CWH	$4,321	$17,197	$21,518	$1,530	5%	95%	3.0	3.7

* Discounted

[12] Large differences in the average and median values for PBP are due to outliers in the distribution of results. A limited number of excessively long PBPs produce an average PBP that is very long. Therefore, the median PBP usually is a more representative value to gauge the length of the PBP.

Table 9. LCC and PBP Results for Replacement and New Construction Cases (SOUTH)

Option	Life-Cycle Cost *(2009$)*			Life-Cycle Cost Savings			Payback Period	
	Average Installed Price	Average Lifetime Operating Cost*	Average LCC	Average Savings *(2009$)*	Households with Net Cost	Households with Net Benefit	Mean *(years)*	Average *(years)*
REPLACEMENT								
NCGF/NCWH	$2,608	$9,989	$12,597					
NCGF/CWH	$3,675	$9,651	$13,326	-$729	93%	7%	34	56
CGF/NCWH	$3,273	$9,446	$12,719	-$121	73%	27%	23	32
CGF/CWH	$4,196	$9,108	$13,304	-$707	84%	16%	25	36
NEW CONSTRUCTION								
NCGF/NCWH	$3,709	$11,398	$15,109					
NCGF/CWH	$4,225	$11,067	$15,294	-$185	65%	35%	18.1	33.1
CGF/NCWH	$4,066	$10,789	$14,857	$252	44%	56%	11.9	20.2
CGF/CWH	$4,005	$10,458	$14,464	$644	28%	72%	5.6	9.7

* Discounted

Figure 2: Option with the Lowest LCC (Fraction of Households)

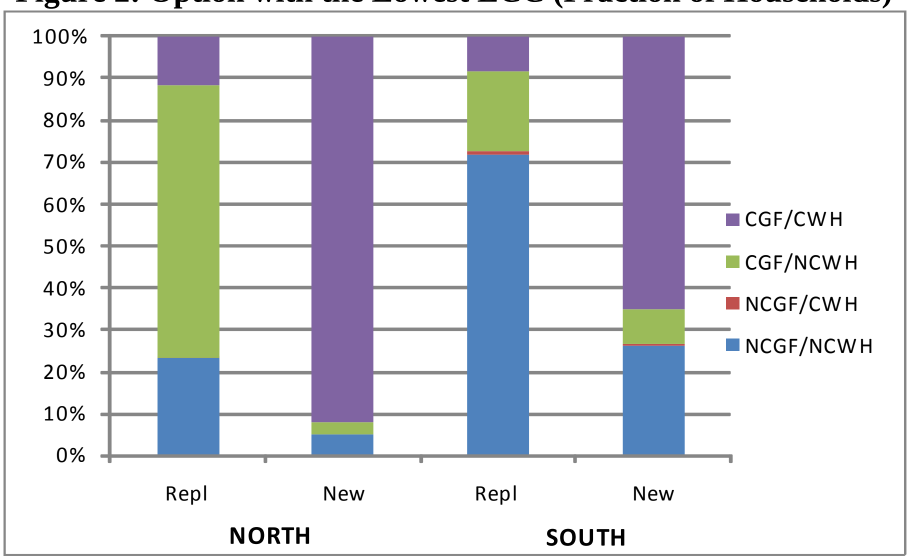


Table 10. Option 4 results for Replacement Cases in North Subregions

	Average LCC Savings	% Households with Net Benefit	Average Payback Period (years)	Fraction of National Sample
Northeast	$159	48%	13.5	12.6%
Midwest	$83	44%	14.4	42.3%
Northwest	-$53	38%	15.4	8.8%
Total North	$80	44%	14.3	63.6%

Discussion

The results assume that the consumer product cost for a condensing water heater falls to levels that are well below the prices that are likely in the near term. The assumed prices could come about if production rises to a significant level, or if subsidies lower the cost to consumers. The recently established Federal standards for large-volume gas water heaters, which will take effect in 2015, require condensing technology, and thus will increase production. To some degree, economies of scale in production of large-volume gas water heaters could spill over into the more common tank sizes.

This study did not consider all possible options for space heating and water heating combinations. Other options that could be attractive for some consumers include: gas tankless water heaters, heat pump water heaters, heat pump space heaters, and solar water heaters, as well as other combination space heating/water heating equipment types.

Conclusion

For the U.S. single family housing market the most common combination of water heating and space heating is a gas furnace with a gas water heater. This study found that at a national level, using a condensing furnace and a condensing water heater would show economic benefit for close to one third of household replacement installations and for a large majority of new construction if they are installed at the same time.

The economics of installing condensing furnaces and condensing water heaters are most favorable in the North. In this region the CGF plus CWH option has a positive LCC savings for replacement situations, mostly due to avoiding chimney relining costs when installing condensing equipment. Still, less than half of the sample households have a net benefit. In the South, the CGF plus CWH option is still quite attractive in new construction, but none of the options has positive average LCC savings in the replacement sample.

The economic results for the CGF plus CWH option vary among parts of the North due mostly to variation in energy prices and energy use. The economics are most favorable in the Northeast and Midwest, which account for more than 80 percent of the gas furnace and water heater households in the North.

The economic results indicate that significant energy savings and consumer benefits may result from large-scale introduction of condensing water heaters combined with condensing furnaces in U.S. residential single-family housing, particularly in the North. It also shows that important benefits may be overlooked when policy analysts evaluate the impact of space and water heating equipment separately.

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