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July 27, 2021

British Columbia Public Interest Advocacy Centre
Suite 803 470 Granville Street
Vancouver, B.C.
V6C 1V5

Attention: Ms. Leigha Worth, Executive Director

Dear Ms. Worth:

Re: FortisBC Energy Inc. (FEI)

Application for a Certificate of Public Convenience and Necessity (CPCN) for Approval of the Coastal Transmission System Transmission Integrity Management Capabilities Project (Application)

Response to the British Columbia Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre *et al.* (BCOAPO) Information Request (IR) No. 1

On February 11, 2021, FEI filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-149-21 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCOAPO IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1.0 Reference: Exhibit B-1, Section 3.2.2.3

Preamble: In Section 3.2.2.3, FEI discusses hydrostatic testing stating "Once a pipeline has been constructed, coated and buried, it is subjected to a hydrostatic test" prior to being placed in service.

1.1 Please confirm that each segment of pipe that is included in the TIMC project were subjected to hydrostatic testing when constructed. If not, please explain fully why not.

Response:

FEI confirms that each segment of pipe that is included in the Project would have been subjected to hydrostatic testing when constructed.

1.2 FEI states that a minimum test factor of 1.25 is sufficient. Please discuss in detail FEI's position on whether there is any correlation between hydrostatic test results and any subsequent corrosion or cracking.

Response:

FEI has not observed a correlation between hydrostatic test results and any subsequent corrosion or cracking in its system, nor would it expect one. A hydrostatic test immediately after construction is expected to remove pre-existing manufacturing and construction flaws (up to a certain size depending on the test pressure), whereas subsequent corrosion or cracking is caused by the post-construction operating environment. In alignment with Section 3.2.2.3 of the Application:

- Pipe with a minimum test factor of less than 1.25 has is an increased failure risk due to potential manufacturing and construction flaws that could have existed in the pipeline since the time of original construction; and
- Pipe that is subjected to time-dependent steel-weakening processes such as corrosion or stress corrosion cracking, regardless of its minimum test factor, has a potential failure risk due to those time-dependent mechanisms interacting with manufacturing and construction flaws that could have existed in the pipeline since the time of original construction.

FEI requested that JANA also provide a response to BCOAPO IR1 1.2. JANA provides the following response:

JANA agrees with the FEI response.

1.3 Please confirm whether FEI's position on correlation between hydrostatic test results and any subsequent corrosion or cracking is the same as industry best practice and if not, please provide a description of all differences and all congruencies between the two.

Response:

While FEI has not conducted any formal analysis, and bases its response on its general experience including its industry knowledge activities (as described in Section 3.3.2 of the Application), FEI's understanding is that its position on correlation between hydrostatic test results and any subsequent corrosion or cracking is the same as industry best practice.

FEI requested that JANA also provide a response to BCOAPO IR1 1.3. JANA provides the following response:

JANA agrees that the FEI position aligns with industry best practice.

1.4 If the segments were tested, please provide the hydrostatic test results.

Response:

All segments included in the CTS TIMC Project were hydrostatically tested in accordance with CSA Z662 to either a minimum of 1.25 or 1.4 times the maximum operating pressure, depending on the class location of the pipeline. Consequently, all pipeline segments passed hydrostatic testing prior to being put into service.

Given that the CTS is made up of multiple pipelines and has been extensively modified over the decades since its initial construction, the complete set of hydrostatic test results for all pipeline segments and station equipment would comprise hundreds of records. Locating, collecting, and providing all of the individual test results would require considerable effort, with little offsetting benefit to the evidentiary record. On this basis, FEI respectfully declines to provide the requested test results.

FEI provides as Attachment 1.4 the hydrostatic test records for the ROE TIL 914 pipeline which was installed in 1981 as an example of the results typically obtained. Over the years, 10 pipeline alterations have taken place that each required their own records and proof of hydrostatic testing. The three sample record sets attached represent the initial installation in 1981 (Attachments 1.4a and 1.4b) and one alteration in 2002 (Attachment 1.4c).

2.0 Reference: Exhibit B-1, Section 3.2.3.2

Preamble: On PDF page 33 of 414, starting at line 23, FEI states discusses its IMP-P program stating:

- Design, material selection, and procurement;
- Construction, including installation, inspection, and quality assurance and control;
- Operations and maintenance, which includes:
  - Vegetation management and pipeline patrol for preventing third-party damage;
  - Water crossing inspections and seismic mitigation for preventing failures due to natural hazards; and
  - Pipeline condition monitoring using ILI for detecting and sizing of geometric imperfections (e.g., dents, wrinkles, and buckles) and metal loss imperfections (e.g., corrosion and gouges).
- Emergency preparedness, response, and recovery; and
- Risk management.

2.1 For each item listed, please fully describe the FEI processes, and how they impact pipeline reliability. In the response please describe the FEI process as it exists currently, and how each process may change after the implementation of the TIMC project.

Response:

FEI has not forecast potential changes to each process that may occur over time and independent of the TIMC project (both CTS and ITS), such as in response to changes in standards and industry practice unrelated to the TIMC project.

The table below provides information on forecasted changes to FEI processes as a result of the implementation of the TIMC project.

Item	How FEI processes impact pipeline reliability	Forecast process changes as a result of the TIMC project
Design, material selection, and procurement	• Design: Intended to ensure that assets have been designed in compliance with applicable codes, standards, regulations and industry practices; and can meet constructability, reliability, maintainability, and operability requirements in a safe, efficient, economic and environmentally and socially responsible manner. • Material selection and procurement: Intended to mitigate failure incidents associated with material defects and equipment failure attributed to the manufacture or manufacturer's design of the material or equipment.	Learnings from the TIMC project will be used in the design of new and replacement sections of pipelines and stations to ensure optimal tool velocities can be achieved. New ILI facilities will be designed to accommodate a larger range of ILI tools including EMAT.
Construction, including installation, inspection, and quality assurance and control	• Intended to mitigate failure incidents caused during installation by operations personnel and contractors. "Field Quality Management" is a set of protocols that manages human performance risks by ensuring that field work (e.g. construction, operations and maintenance) is completed in a safe and effective manner by following internal and external quality requirements.	This activity is not forecast to change as a result of the TIMC project.
Operations and maintenance, which includes: • **Vegetation management and pipeline patrol for preventing third-party damage**	• Maintenance (general): Maintenance Programs are planned activities that extend the life of the gas system assets by ensuring continued proper operating conditions by using preventative maintenance practices. • Vegetation management: Intended to mitigate failure incidents caused by third-party damage. The provision of clear sight lines to identify the existence of pipelines is a key component of third-party damage prevention. Vegetation management also provides clear access to FEI pipelines and facilities to maintain signage, conduct surveys, and other operations work in order to maintain the integrity of the pipeline system. Vegetation management also manages the risks to FEI pipelines and facilities from hazard trees and root interactions. • Pipeline patrol: Intended to mitigate failure incidents caused by third-party damage. Pipeline patrol is a scheduled activity to monitor for signs of activity or events which might impact the integrity of transmission pipelines.	This activity is not forecast to change as a result of the TIMC project.

Item	How FEI processes impact pipeline reliability	Forecast process changes as a result of the TIMC project
Operations and maintenance, which includes: • **Water crossing inspections and seismic mitigation for preventing failures due to natural hazards**	• Water crossing inspections: Intended to prevent and/or mitigate failure incidents caused by these types of natural hazards. During asset design, geotechnical and hydrotechnical hazards are considered and avoided and/or mitigated where possible. Monitoring and mitigation actions are implemented where required during the asset lifecycle.	This activity is not forecast to change as a result of the TIMC project.
Operations and maintenance, which includes: • **Pipeline condition monitoring using ILI for detecting and sizing of geometric imperfections (e.g., dents, wrinkles, and buckles) and metal loss imperfections (e.g., corrosion and gouges)**	• In-line inspection: Intended to identify, size, and monitor anomalies (e.g., metal loss, dents, mechanical damage, buckles, wrinkles, cracking, and manufacturing flaws) that may adversely affect the integrity of specific in-line inspected pipelines.	Pipeline condition monitoring using ILI will be expanded to include EMAT for management of SCC and crack-like imperfections. This will provide the required data for FEI to mitigate failure due to cracking.
Emergency preparedness, response, and recovery	• Emergency preparedness: Intended to ensure verifiable capability to respond to an emergency in accordance with emergency procedures and response plans, and to demonstrate the effectiveness of such procedures and plans.	This activity is not forecast to change as a result of the TIMC project.

Item	How FEI processes impact pipeline reliability	Forecast process changes as a result of the TIMC project
Risk management	• Risk management: Intended to identify, assess, and manage the hazards and associated risks for the life cycle of the pipeline system.	FEI forecasts that the data provided through EMAT in-line inspections, including subsequent integrity digs and analysis, will improve its capabilities for ongoing quantitative risk assessments of cracking threats on its transmission pipelines.

3.0 Reference: Exhibit B-1, Section 3.2.5

Preamble: In section 3.2.5, FEI discusses how its existing integrity management practices do not identify all cracking**.**

3.1 Please provide all quantitative analysis or incidents of cracks identified that were not identified by FEI's current integrity management practices.

Response:

FEI's existing integrity management practice for identifying cracking includes "opportunity digs". Please refer to the response to CEC IR1 17.2 for the incidents of cracks identified through FEI's EMAT ILI pilot work (i.e., the cracks that were not identified through opportunity digs).

3.2 Please provide all FEI quantitative analysis that clearly demonstrates the incidents of cracking have increased over each of the last 10 years.

Response:

FEI is unable to provide any quantitative analysis that demonstrates the incidents of cracking increasing over each of the last 10 years because, as noted in the preamble, FEI's existing integrity management practices do not identify all cracking. As discussed in Section 3.2.5 of the Application, FEI estimates that the total amount of pipeline exposed to date as part of its Integrity Dig Program (and hence assessed for cracking) is less than one percent of the total length of pipe in FEI's transmission system. This provides insufficient data from which to quantitatively assess any potential increase in cracking on FEI buried pipelines since original construction.

However, as discussed in Section 3.2.4.1 of the Application, stress corrosion cracking is a time-dependent integrity threat, meaning that its potential to impact the pipeline will increase over time if not appropriately mitigated. The nature of cracking threats is such that the risk increases over time and therefore must be appropriately mitigated.

4.0 Reference: Exhibit B-1, Section 3.4.3

Preamble: In section 3.4.3, FEI discusses how CTS and ITS are susceptible to cracking threats

4.1 Please confirm whether, once this application is approved and the CPCN-related work complete, FEI will seek approval for similar applications, related to other portions of the FEI system.

4.1.1 If so, please provide all relevant information – including project scope, projected cost, and timing – of all planned or contemplated similar applications.

Response:

FEI has indicated in the Application[1] that it is developing a further TIMC project for work on the FEI Interior Transmission System (the ITS TIMC Project). The requested information on the ITS TIMC Project is provided below.

Requested information	Response
Project scope	In the ITS TIMC Project, FEI plans to address the ITS pipelines that were assessed as being susceptible to cracking as per the QRA report completed by JANA Corporation and for which EMAT ILI tools are commercially available. In alignment with the CTS TIMC Project, FEI expects to seek approval for associated pipeline modifications that are required to enable in-line inspection with EMAT tools. Specific pipeline and facility scope is under development.
Projected cost	As the specific scope remains under development, FEI is not able to provide a total projected cost at this time.
Timing	FEI plans to file an application for the ITS TIMC Project with the BCUC in 2022.

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[1] Sections 1.1, 1.2.2, 3.4.1, 5.3.2, and 6.2.

5.0 Reference: Exhibit B-1, Section 3.4.4

Preamble: In Section 3.4.4, FEI discusses the QRA undertaken by JANA and the risk level and associated risk drivers for the CTS.

5.1 Please confirm that the implementation of the TIMC project will reduce the risk of unplanned or catastrophic failures.

5.1.1 If not confirmed, please fully explain why the TIMC will not reduce the risk of unplanned or catastrophic failures.

5.1.2 If confirmed, please specify the degree to which FEI expects the TIMC will reduce the risk of unplanned or catastrophic failures, providing evidence to support that quantification.

Response:

Confirmed. EMAT ILI and subsequent integrity management activities will reduce the risk of unplanned or catastrophic failures due to cracking threats, to the extent that EMAT ILI detects cracking threats on FEI pipelines over their lifecycle. At this time, FEI cannot estimate the degree the TIMC project will reduce the above-noted failures as the data collected from the pilot project and other EMAT ILI results are not yet ready for interpretation and FEI has not undertaken its second iteration of a QRA. However, FEI's estimates of risk will change over time and will be influenced by FEI's ongoing integrity management activities to mitigate the time-dependent threat of cracking to an aging pipeline system.

5.1.3 If confirmed, please fully explain how the reduced risk would specifically impact the business risk that is part of a cost of capital proceeding. In the response, please fully explain the implementation of systems and processes that reduce risks, at customer cost, reduce the business risk of a utility, and reduce the allowed equity thickness or allowed ROE of a utility.

Response:

The business risk analysis conducted for cost of capital determination purposes is mainly qualitative in nature and considers the Company's business risk profile in its entirety. As such, it is not possible to quantitatively estimate the impact of individual risk events or operational risk mitigation projects on FEI's allowed ROE or equity thickness. It is, however, possible to discuss the risk impacts directionally.

As stated in the response to BCOAPO IR1 5.1, the TIMC project will improve FEI's operational risk as it helps FEI better identify time dependent threats that may cause catastrophic and unexpected failures. As a safety-driven project, the TIMC project will not generate additional revenue on its own and the associated cost recovery from customers will result in higher rates and reduced price competitiveness leading to higher price risk. These two factors will serve to offset each other in determining overall business risk but, as stated above, it is not possible to quantify the impact.

5.2 Please fully explain FEI's risk targets and goals.

5.2.1 Is it FEI's goal to take all risks to zero?

5.2.2 Provide a full discussion and analysis of the cost of risk mitigation and risk reduction, including a discussion of the relation between cost and risk reduction.

<u>Response:</u>

FEI provides the following response:

Any ruptures of FEI's transmission pipelines are unacceptable to FEI, the public, and its regulators. As part of FEI's Integrity Management Program for Pipelines, FEI strives to have zero failure incidents[2] or other incidents involving the functionality of the gas system assets that could result in the following consequences:

- **Safety:** Serious injury or worse to any person (employee, contractor, customer, or public); and/or
- **Environment:** An estimated irreversible, long-term, or continuous change to the ambient environment in a manner that causes harm to human life, wildlife, or vegetation; and/or
- **Service Disruption:** Outage that impacts a large number of customers.

FEI, in alignment with industry best practices, endeavours to implement integrity management activities that mitigate threats to its transmission pipelines. Even so, FEI recognizes that residual risk cannot be reduced to zero.

FEI considers the risk benefits and cost of projects on an individual project basis. Please refer to the response to BCUC IR1 12.1 for FEI's discussion of cost as it pertains to FEI's risk mitigation proposed by the CTS TIMC Project.

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[2] A failure incident is defined in CSA Z662-19 as "an unplanned release of service fluid".

FEI requested that JANA also provide a response to BCOAPO IR1 5.2, 5.2.1 and 5.2.2. JANA provides the following response:

It is JANA's opinion that FEI's risk targets are consistent and aligned with those of the North American gas pipeline industry.

It is JANA's opinion that it is not possible to reduce risk to zero for any activity or pipeline operation.

Once a risk has been identified within the pipeline system requiring mitigation then the most cost-effective mitigation approaches should be considered, as FEI has done in the CPCN submission.

5.3 Please provide responses to the above questions from each of FEI and JANA's perspectives.

Response:

Please refer to the response to BCOAPO IR1 5.2.

5.4 Please fully explain what FEI will do if the BCUC denies its intention to recover the project costs through customer rates. Would FEI still implement the project?

Response:

FEI submits that the CTS TIMC Project is in the public interest, necessary, and the most cost-effective way for FEI to mitigate the identified cracking risk to the 11 CTS pipelines and, therefore, that the BCUC should issue a CPCN for the Project. If the BCUC issues a CPCN, FEI must be provided a reasonable opportunity to recover its prudently incurred project costs through customer rates. As the BCUC stated in its Decision on the Inland Gas Upgrade project (at p. 41), "there is no regulatory requirement for FEI's shareholder to fund pipeline integrity management initiatives."

If the BCUC did not issue a CPCN or, for some other reason, denied recovery of project costs through rates, FEI would need to consider the BCUC's reasons and assess its options at that time. As cracking threats must be mitigated, FEI would need to address whatever concerns the

BCUC identified in its Decision and seek the appropriate approvals to move forward with the Project.

Please also refer to the response to BCUC IR1 4.6.

5.5 Please fully explain how the implementation of projects such as this impacts FEI insurance costs.

Response:

FEI designs, constructs, operates, and maintains its assets in order to provide safe and reliable energy delivery to its customers. These efforts are key to preventing losses and resulting insurance claims. Insurers review FEI's assets and operations annually to understand the potential hazards associated with its business. They assess how FEI monitors, maintains, and improves these assets. Insurers expect utilities such as FEI to implement projects that enhance pipeline integrity and resiliency. It is also because of projects like these that FEI continues to present itself as a favourable risk to insurers. FEI has not experienced additional increases in insurance premiums (other than factors driven by market conditions).

6.0 Reference: Exhibit B-1, Section 5.3.3

Preamble: In Section 5.3.3, FEI discusses an EMAT ILI Pilot Project. FEI states that there was no severe cracking that required urgent repair work.

6.1 Please provide an analysis of all pilot results identifying cracks, corrosions, or other anomalies.

Response:

Please refer to the response to CEC IR1 17.2 for EMAT ILI pilot project results identifying cracks and crack-like anomalies in FEI's system.

6.2 For each anomaly, please specify all possible recommended actions including:
repair the anomaly,
replace the segment of pipe,
conduct an exploratory dig to verify the findings,
actively monitor the anomaly,
do nothing,
any other action (specifying what that action might be).

Response:

Please refer to the response to CEC IR1 17.2.

6.3 For each anomaly, please specify what action of the recommended possibilities FEI prefers and why.

Response:

Please refer to the response to BCUC IR1 11.1. At this stage of the EMAT ILI Pilot project, FEI chose to remove crack-like features for further advanced non-destructive and destructive testing as part of its validation process of tool performance and testing methodology. Subsequent decision-making regarding FEI's integrity management practices will be based on the validation results and severity of crack or crack-like anomalies found.

6.4 Please provide the criteria used to determine the action chosen in the question above.

Response:

FEI used its interpretation of its obligations for maintaining compliance with CSA Z662 to determine that cracks should be removed by grinding or cut out for further testing. Destructive testing is performed by FEI and its industry peers to evaluate, with increased certainty, aspects of cracking such as sizing and type (e.g. SCC or other cracking causes). It also enables FEI to validate EMAT tool performance and non-destructive evaluation methods for future in-ditch crack characterization (i.e. during integrity digs), and provides other material testing opportunities.

CSA Z662:19 includes the following relevant excerpt:

> 10.10.5 Pipe body surface cracks: "Pipe body surface cracks shall be considered to be defects unless determined by an engineering assessment to be acceptable. The engineering assessment shall include consideration of service history and loading, anticipated service conditions (including the effects of corrosive and chemical attack), the mechanism of crack formation, crack dimensions, crack growth mechanisms, failure modes, and material properties (including fracture toughness properties). Pipe containing such defects shall be repaired using one of more of the acceptable repair methods given in Table 10.2."

To facilitate FEI's engineering assessments, destructive testing can provide, with varying degrees of confidence and completeness dependent on the specific situation and tests performed, information such as the:

- Crack formation mechanisms;
- Crack growth mechanisms;
- Crack dimensions; and
- Material properties.

6.5 Please discuss how FEI will develop or implement criteria for action based on EMAT ILI findings. Will FEI file an application with the Commission to test and vet those criterion?

Response:

Cracks on pipelines are considered to be defects unless determined by an engineering assessment to be acceptable, as per Clause 10.10.5 of CSA Z662:19. Therefore, the criteria for any action based on EMAT ILI findings will be situational and determined based on the experience and judgement of engineering professionals. FEI does not intend to file a separate application with the BCUC to test and vet those criteria.

7.0 Reference: Exhibit B-1, Section 5.4.2

Preamble: In Section 5.4.2, FEI discusses heavy wall segment replacement.

7.1 Please confirm that the main reason for the replacement of heavy wall pipe is the speed excursions that the EMAT ILI tool experiences with heavy wall pipe. If not confirmed, please fully explain.

Response:

The main reason for the replacement of heavy wall pipe is to avoid EMAT ILI tool speed excursions caused by transitions from heavy wall pipe to the thinner wall pipe located immediately downstream of the heavy wall pipe. Please also refer to the response to BCUC IR1 14.3 for further explanation.

7.2 Please confirm that for adjacent sections of pipe that are not heavy wall pipe, no such excursions exist and that the EMAT ILI tool functions normally. If not confirmed, please fully explain.

Response:

Not confirmed. As explained in the response to BCUC IR1 14.3, the speed excursions take place in the thinner wall pipe located immediately downstream of the heavy wall pipe.

7.3 Please provide a detailed assessment of the condition of the heavy wall segments. Are the heavy wall segments more resistant to cracking and corrosion that would require remediation action, less resistant, or the same as any adjacent sections that are not of heavy wall construction?

Response:

Heavy wall sections proposed for replacement through the CTS TIMC Project need to be replaced not because of their condition, but because of their contributing effect on speed excursions for downstream thinner wall pipe. FEI characterizes the condition of its heavy wall pipe segments as fit for service from a pressure-containment perspective, but as impeding its ability to collect in-line inspection data of sufficient quality. Heavy wall segments are not more resistant to cracking and corrosion; however, as they typically have lower stress levels than adjacent thinner wall pipe, they do have more resistance to failure (i.e., critical flaw sizes can be relatively larger).

8.0 Reference: Exhibit B-1, Section 5.5.3

8.1 Please fully explain how the optimum velocity can be achieved. Could the optimum velocity be achieved by choosing the season for the test, so it is not at peak season, with highest pressure, or lowest season with lowest pressure instead of implementing a Flow Control Station?

Response:

Please refer to the response to BCUC IR1 18.1.

9.0 Reference: Exhibit B-1, Table 5-9

Preamble: In Table 5-9, FEI discusses the project schedule. A number of activities are schedules prior to the CPCN approval.

9.1 Please fully explain who, FEI or Customers, are responsible for any costs incurred prior to CPCN approval, should the Commission deny such approval.

<u>Response:</u>

The Project's Preliminary Stage Development Costs, Pre-Construction Development Costs, and Application Costs, which FEI incurs prior to approval of the Application, have been prudently incurred and are necessary expenditures to ensure the CPCN Application has been developed to the degree required by the BCUC's CPCN Guidelines, as well as to support the pipeline failure risk mitigation addressed by the Project. On this basis, these costs are recoverable from ratepayers.

Please also refer to the response to BCOAPO IR1 5.4.

10.0 Reference: Exhibit B-1, Section 5.9.1

10.1 In this section of the Application, FEI discusses Federal permits and environmental assessments. Please fully explain the nature of the permits and assessments and the impact on project timing if the approvals are (i) delayed, or (ii) denied.

Response:

As described in Section 7.2 of the Application, FEI retained Stantec Consulting Ltd. to undertake a preliminary Environmental Overview Assessment (EOA). The results of this assessment identified the potential need for certain permits. Additional environmental studies are planned during the Project's detailed design phase to verify if all the permits identified in the preliminary EOA will ultimately be required.

In order to mitigate the risk of any permitting-related delay, FEI will undertake early engagement with stakeholders and Indigenous groups throughout the detailed design process to proactively identify permitting requirements and incorporate any feedback into the Project's design. FEI will also work with permitting agencies to confirm anticipated permit application review timelines and will prepare a detailed permit schedule that aligns with the Project schedule.

If the receipt of a permit is delayed, FEI will not commence planned construction in areas where that permit is required. Project schedule accounts for permits from the Ministry of Transportation and Infrastructure, Metro Vancouver, and CP Rail that are anticipated to have longer lead times (12 to 18 months) than the permits identified in Section 5.9.1 of the Application (6 to 12 months). Up to a 6 month delay in the permitting process would not impact the overall Project schedule.

In the unlikely event a permit is denied, FEI will work diligently with the applicable permit agency to resolve areas of concern. Again, FEI will not commence construction in an area until all relevant permits are obtained and the associated permitting requirements have been fulfilled.

11.0 Reference: Exhibit B-1, Table 6-2

11.1 In table 6-2, FEI lists costs as $133.018 million in 2020 dollars and $137.843 million as spent. In confidential appendix G, in the "project costs" tab, the total as spent is different. Please fully explain the reason or reasons for this difference without making reference to any specific information subject to confidentiality constraints.

Response:

FEI clarifies that the total project costs in as-spent dollars shown in Confidential Appendix G, Project Costs tab, is before the AFUDC and tax offset shown on Line 11 and 12 of Table 6-2 of the Application. Please refer to the table below which reconciles the as-spent dollars shown in Table 6-2 and in the Project Cost tab of Confidential Appendix G.

Line	Item	As-Spent ($ millions)	Reference
1	Project Capital Costs	94.362	Table 6-2, Line 4
2	Contingency	15.624	Table 6-2, Line 6
3	Development and Deferral Costs	30.824	Table 6-2, Line 10
4	Total Project Cost before AFUDC and Tax Offset	140.810	Sum of Line 1 to 3; Conf. App. G, Project Cost tab
5	AFUDC	6.150	Table 6-2, Line 11
6	Tax Offset	(9.117)	Table 6-2, Line 12
7	Total Project Cost	137.843	Table 6-2, Line 13

12.0 Reference: Exhibit B-1, Table 6-3

12.1 Please confirm that "Capitalized Development Costs" of $13.877 million will be included in FEI Rate Base. If not confirmed please fully explain.

Response:

Confirmed.

12.2 Please provide the criteria that FEI applied to allow the capitalization of development costs.

Response:

Consistent with the responses provided to BCUC IR1 21.1.1 related to the TIMC Deferral Account in the FEI Annual Review for 2019 Delivery Rates (excerpted below), the development costs in Table 6-3 have been assessed under US GAAP, including ASC 360, Property, Plant and Equipment, and ASC 970-340, Real Estate-Other Assets and Deferred Costs. The development costs in Table 6-3 have been determined to be outside of the preliminary phase, where costs are expensed or deferred, and part of the pre-construction phase. This phase is determined by a specific project being identified, management authorizing funding, financial resources being available to execute, and the probability that necessary conditions and regulations to construct the project will be met. In this phase, certain costs are eligible to be capitalized if they are directly attributable to the project. The costs that have been identified for capitalization are explained under Table 6-1 as being related to the quantitative risk assessment of FEI's transmission pipeline assets and EMAT inspection costs.

An excerpt from Exhibit B-3, Response to BCUC IR1 21.1.1 in the FEI Annual Review for 2019 Delivery Rates proceeding is provided below:

> 21.1.1 As part of the above response, please identify which of the Phase 1 costs would be classified as O&M and which would be classified as capital in accordance with US GAAP and why (in the absence of an approved deferral account).
>
> <u>Response:</u>
>
> As described in section 12.4.1.1 of the Annual Review for 2019 Rates filing, the expenditures for Phase 1 relate to "work to assess long-term system implications for adopting EMAT technology and to determine the scope of work". In the absence of an approved deferral account for a rate regulated entity such as FEI,

the costs incurred during Phase 1 of the TIMC would generally be expected to be classified as O&M expenditures pursuant to US GAAP, including ASC 360 Property, Plant and Equipment and ASC 970-340 Real Estate Other Assets and Deferred Costs.

The classification of Phase 2 costs between O&M and capital requires a degree of professional judgement when applying the accounting guidance. Once Phase 1 has been completed, there is a high probability that this asset is required to be constructed. If this probability requirement is satisfied, the project is considered as part of the pre-acquisition phase under US GAAP, which in turn permits the capitalization of various project costs. Costs to develop the CPCN application may be classified as O&M in absence of a regulatory approved deferral account, while the front-end engineering design costs are likely to meet the capitalization criteria under US GAAP.

12.3 Please confirm that TIMC Deferral Additions of $13.243 million will not be included in rate base. If not confirmed please fully explain.

Response:

FEI confirms that, in the cost accumulation stage prior to BCUC approval, the TIMC Deferral Additions of $13.243 million are recorded in a non-rate base deferral.

As noted in the response to BCUC IR1 26.2, FEI has amended the approvals sought for the non-rate base deferral to transfer to a rate base deferral on January 1, 2023, and to commence with amortization over a three-year period at that time.

12.4 If 12.3 above is confirmed, please fully explain why TIMC Deferral additions are not included in Rate Base.

Response:

Please refer to the response to BCOAPO IR1 12.3.

Attachment 1.4

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Roebuck-Tilbury Loop
Hydrostatic Test Procedure

914 mm Ø Pipe

PIPELINE PROOF TEST REPORT

Test Section Sunison Station

Date Test Completed [illegible] 3 /800K 19 81

Location - From Sunison Station (legal description) to Roebuck Station (legal description)

NOT including both station.

SPECIFICATION

The above hydrostatic proof test was carried out in accordance with HYDRO Specifications, Part 5. The results and calculations shown on the attached pipeline Test Report and on all pressure recorder and temperature recorder charts submitted in support of such Test Report, have been accurately calculated and reported.

Alberta Mobile Air
(Name of Contractor)

PER: [illegible]
(Contractor's Representative)

B. C. HYDRO
3777 Lougheed Highway
Burnaby, B. C.

P.Eng
(Engineer)

Dated [illegible] 3, 19 81

MINISTRY OF TRANSPORTATION AND HIGHWAYS
ENGINEERING & INSPECTION BRANCH
K Kraus
DATE: July 26/82

Appendix IV - 8

GR58L

Attachment 1.4a

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Roebuck-Tilbury Loop
Hydrostatic Test Procedure

PIPELINE TEST REPORT - PAGE 1

GENERAL DESCRIPTION

Test Section 1 From Station Swenson To Station Roebuck
Length 73[illegible] M., 36" mm O.D., 8.92 mm W.T. Spec. GR414 MPa. CSA Z245.2 M
Test Point (T.P.) Elev. -0.2 Metres, High Point (H.P.) Elev. 1073 Metres, Low Point (L.P.) Elev. -0.2 Metres
Reference Drawing No. GD 10340-45
Station Contractor Alberta Mobile Air M.B. Construction
Testing Contractor Alberta Mobile Air

TEST EQUIPMENT (Make/Serial No.)

Pressure Recorder PFM 1193 Bimbarg
Dead Weight Tester M121-81 OPSCO
Temperature Recorder PM 1185
Pressure Dial Gauges - Fill End Roebuck 7050 KPa
- Remote End Swenson 7410 KPa
Compressor or Pump

TIME AND DATE OF TESTS

Filling - Start Nov 26 81 1300K Complete Dec 1 81 1500K.
Leak Test - Start [illegible] Dec 1 81 Complete 1300K Dec 2, 81
Proof Test - Start [illegible] Dec 2/81 Complete 1800 K Dec 3/81

PERSONNEL

Test Supervised By [illegible]
Readings Taken By [illegible]
Test Witnessed By [illegible]
(ENGINEER)

MINISTRY OF TRANSPORTATION AND HIGHWAYS
ENGINEERING & INSPECTION BRANCH
DATE: July 26/82

Appendix IV - 9

GR53L

Attachment 1.4a

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Roebuck-Tilbury Loop
Hydrostatic Test Procedure

PIPELINE TEST REPORT PAGE 2

Test Section Steveston.
Pipe O.D. 36"⌀
Wall Thickness 8.92 mm.
Pipe Spec. GR 414 MPa.
CSA Z245.2M.

LEAK REPORT

First Indication of Leak - Time N.L. Date ________

Nature of Indication ________

Phase of Test in which leak was indicated ________

Measured pressure at test point ________

Location of Leak - Time ________ Date ________

Method used to locate leak ________

Station and/or distance from nearest section line, and elevation of pipe ________

Nature of leak ________

Number of metres of pipe involved ________

Make sketch on back of this page ________

Repair of Leak Completed - Time ________ Date ________

How repair was made ________

Replaced with ____ Metres of ____ O.D. x ____ W.T. Pipe

Additional Remarks ________

Signatures:

(Test Supervisor)

(ENGINEER)

MINISTRY OF TRANSPORTATION
AND HIGHWAYS
ENGINEERING & INSPECTION BRANCH
DATE: July 26/82

①

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Roebuck-Tilbury Loop
Hydrostatic Test Procedure

PIPELINE TEST REPORT - PAGE 3

Test Section Svenson - Roebuck

Pipe O.D. 36"

Wall Thickness 8.92 mm

Pipe Spec. Gr 414 MPa CSA . Z245 . 2M

24 Hour Proof Test (Log of Pressures and Temperatures)

Time (local)	Chart Pressure mPa	Dead-weignt Pressure mPa	Temperature °C			Remarks
			Fill End	Remote End	Ambient	
[illegible] 3 45 pm	7455	7455			+6°	[illegible]
4 45	7440	7440			+4°	
5 45	7440	7440			+2°	
6 45	7440	7440			+2°	
7 45	7435	7435			+2°	
8 45	7430	7430			0°	
9 45	7430	7430			0°	
10 45	74.25	7425			-1°	
11 45	7420	7420			-1°	
12 45	7420	742[illegible]			-1°	
[illegible] 1 45	742[illegible]	7420			-1°	
2 45	742[illegible]	742[illegible]				
3 45	742[illegible]	742[illegible]			+1	
4 45	742[illegible]	742[illegible]			+1°	

MINISTRY OF TRANSPORTATION
AND HIGHWAYS
ENGINEERING & INSPECTION BRANCH
K Krause
DATE: July 26/82

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Roebuck-Tilbury Loop
Hydrostatic Test Procedure

PIPELINE TEST REPORT - PAGE 3

Dec 3/81

Test Section [illegible] - Roebuck
Pipe O.D. 36"
Wall Thickness 8.92 MM
Pipe Spec. GR 414 MPA (5A7 2X).2M

24 Hour Proof Test (Log of Pressures and Temperatures)

Time (local)	Chart Pressure mPa	Dead-weight Pressure mPa	Temperature °C			Remarks
			Fill End	Remote End	Ambient	
5.45 am	7420	7420			+2	
6.45	7420	7420			+2	
7:45	7420	7420			+2	
8:45	7415	7415			+2	
9:45	7415	7415			+1	
10:45	7415	7415			+2°	
11:45 am	7415	7415			+2°	
12:45 pm	7415	7415			+2°	
1:45	[illegible]	[illegible]			+3°	
2:45	7415	7415			+3°	
3:45 pm	7415	7415			+3°	

MINISTRY OF TRANSPORTATION
AND HIGHWAYS
ENGINEERING & INSPECTION BRANCH
DATE: July 26/82

Attachment 1.4a

Dec 3/81 Roebuck

12 noon	Pressure	7050 KPA
1 AM	"	7050 KPA
2 AM	"	7050 KPA
3 AM	"	7050 KPA

MINISTRY OF TRANSPORTATION
AND [illegible]
ENGINEERING & INSPECTION BRANCH
K K
DATE: July 26/82

ENGINEERING BRANCH

INSPECTOR'S PIPELINE REPORT

Attachment 1.4a

BC HYDRO

CTOR H+B CONSTRUCTION

ECTOR

LD SURREY

JECT NO. 3286

LOCATION SWENSON VALVE STN. SURREY - DELTA

PRODUCT NAT GAS

TIAL PRESSURE OR MOLE PERCENT H_2S

Line No.	Length	Diam.	Wall Thick.	Pipe Code	Pipe Grade	Sour Spec.	Exter. Coat.	Inter. Coat.	Depth of Cover	Class Location		Pressure of Weakest Elemen
1	4.67 MILES	36"	.350	Z 245.2	414	—	POLIKEN	EPOXY	30"	III		
2												
3												
4												
5												
6												

soil type DWT - 7455 KPA 3:45 PM TEMP - +6 - 3:45 PM

pipe weights CHART - READING - 7450 KPH

pipe anchors CHART ON AT - 3:50 PM

aders and traps

ight-of-way width -

Valves — ANSI 300

Fittings ANSI - 300

pressure vessels

relief valve

pump -

compressor

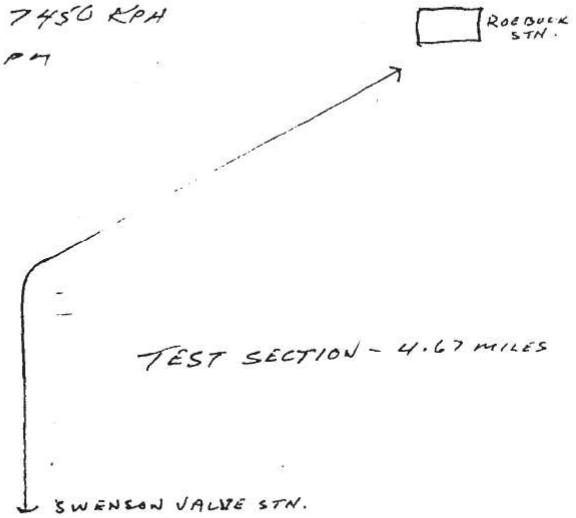
supports

cathodic protection

test leads

ondition of finished R.O.W.

pipeline elevation difference - 270'



road crossings

pipeline crossings

railway crossings

utility crossings

river or creek crossings

Piping Tests Date Dec 2/81 Test Medium WATER

Duration of test 24 HRS (minimum test pressure)

Test Pressure Variation test temperature variation

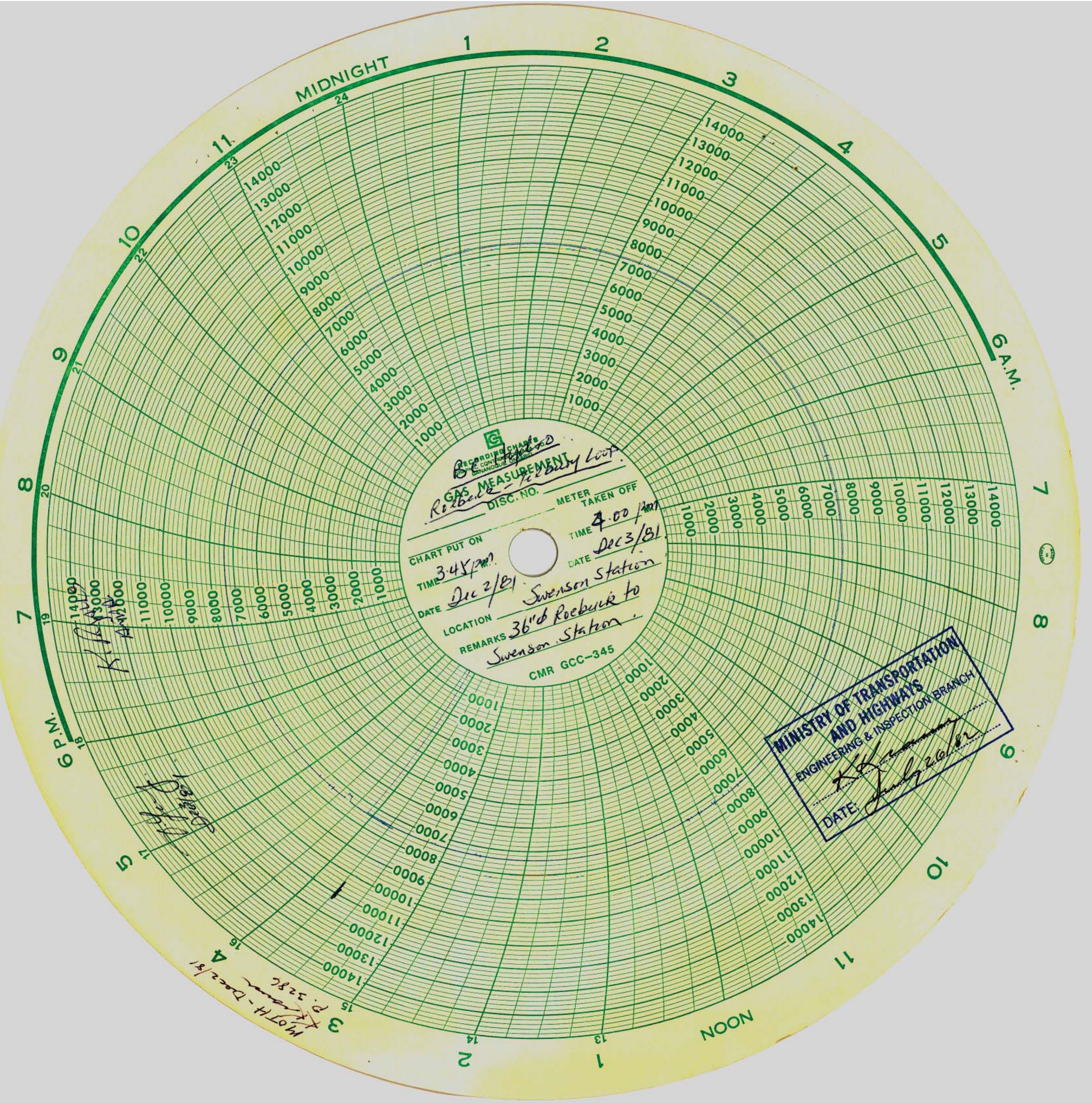
Welders: Names	Ticket No.	Class
1.		
2.		
3.		
4.		

ALTA MOBILE AIR SERVICE

Inspected by K Kraus

Date Dec 2/81

Attachment 1.4a



GAS MEASUREMENT

BC Hydro

Roebuck - Tilbury Loop.

DISC. NO.

METER

CHART PUT ON

TIME 3.45 pm

DATE Dec 2/81

TAKEN OFF

TIME 4.00 pm

DATE Dec 3/81

LOCATION Swenson Station

REMARKS 36"ϕ Roebuck to Swenson Station.

CMR GCC-345

MINISTRY OF TRANSPORTATION AND HIGHWAYS
ENGINEERING & INSPECTION BRANCH
DATE: July 26/82

Dec 3/81

MOTH - Dec 2/81
P. 3286

Attachments 1.4b

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Roebuck-Tilbury Loop
Hydrostatic Test Procedure

914 of pipe

PIPELINE PROOF TEST REPORT

Test Section Swanson Station

Date Test Completed ______________ 19 81

Location - From Swanson Station (legal description) to Tilbury Station (legal description)

include Tilbury station

SPECIFICATION

The above hydrostatic proof test was carried out in accordance with HYDRO Specifications, Part 5. The results and calculations shown on the attached pipeline Test Report and on all pressure recorder and temperature recorder charts submitted in support of such Test Report, have been accurately calculated and reported.

Alberta Mobile Air.
(Name of Contractor)

PER: ______________
(Contractor's Representative)

B. C. HYDRO
3777 Lougheed Highway
Burnaby, B. C.

Vincent [illegible] P.Eng.
(Engineer)

Dated Dec 9, 1981

M.C.T.H

MINISTRY OF TRANSPORTATION
AND HIGHWAYS
ENGINEERING & INSPECTION BRANCH
DATE: July 26/82

Appendix IV - 8

GR58L

Attachments 1.4b

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Roebuck-Tilbury Loop
Hydrostatic Test Procedure

PIPELINE TEST REPORT - PAGE 1

GENERAL DESCRIPTION

Test Section 2 From Station Swenson To Station Tilbury

Length ______ M., 36" mm O.D., 8.72 mm W.T. Spec. GR414 MPa

Test Point (T.P.) Elev. -0.2 Metres, High Point (H.P.) Elev. CSA Z245.2,

______ Metres, Low Point (L.P.) Elev. -0.2 Metres

Reference Drawing No. (D) 10340 - 45.

Station Contractor HB Construction Ltd.

Testing Contractor Alberta Mobile Air

TEST EQUIPMENT (Make/Serial No.)

Pressure Recorder PM. 1183 Pembina

Dead Weight Tester 14121-81 OPSCO

Temperature Recorder PM. 1195.

Pressure Dial Gauges - Fill End Swenson

- Remote End Tilbury.

Compressor or Pump ______

TIME AND DATE OF TESTS

Filling - Start Dec 4/81 Complete Dec 6/81

Leak Test - Start Dec 7/81 Complete Dec 8/81

Proof Test - Start Dec 8/81 Complete Dec 9/81

PERSONNEL

Test Supervised By ______

Readings Taken By KEN Rycula AMA

Test Witnessed By KEN KRAUSE MOTH

(ENGINEER)

MINISTRY OF TRANSPORTATION
AND HIGHWAYS
ENGINEERING & INSPECTION BRANCH
K Krause
DATE: July 26/82

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Roebuck-Tilbury Loop
Hydrostatic Test Procedure

PIPELINE TEST REPORT PAGE 2

Test Section Swenson – Tilbury
Pipe O.D. 36"ø
Wall Thickness 8.92 mm.
Pipe Spec. GR 414 MPa
CSA Z245.2M.

LEAK REPORT

First Indication of Leak - Time 0730 Date Dec 8/81
Nature of Indication Leak at blind flange 12" stub & 4" valve flange at test head Tilbury, 6" flange test head
Phase of Test in which leak was indicated at Swenson Station
Measured pressure at test point 7500 kPa

Location of Leak - Time ______ Date ______
Method used to locate leak ______
Station and/or distance from nearest section line, and elevation of pipe ______
Nature of leak ______
Number of metres of pipe involved ______
Make sketch on back of this page ______

Repair of Leak Completed - Time 0900 Date Dec 8/81
How repair was made tighten bolts, grease valve
Replaced with ______ Metres of ______ O.D. x ______ W.T. Pipe
Additional Remarks ______

Signatures:

(Test Supervisor)

(ENGINEER)

MINISTRY OF TRANSPORTATION AND HIGHWAYS
ENGINEERING & INSPECTION BRANCH
DATE: July 26/82

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Roebuck-Tilbury Loop
Hydrostatic Test Procedure

(1)

PIPELINE TEST REPORT - PAGE 3

include Tilbury Sta

Test Section Swenson - Tilbury
Pipe O.D. 36"
Wall Thickness 8.92 mm.
Pipe Spec. GR 414 Pipe.
CSA Z 245.2M.

24 Hour Proof Test (Log of Pressures and Temperatures)

Dec 8/81

Time (local)	Chart Pressure mPa	Dead-weight Pressure mPa	Temperature °C			Remarks
			Fill End	Remote End	Ambient	
10 30 am	7500	7450.			4°	
11 30 am	7500	7445			6°	
1230	7495	7445			7°	
1 30 pm	7495	7440			7°	
2·30 pm.	7440.	7440			7°	
3.30	7440	7440			6°	
4 30	7440	7440			5°	
5 30	7435	7440			4°	
6 30	7435	7440			4°	
7 30	7435	7440			4°	
8 30	7435	7435			4°	
9 30	7435	7435			4°	
10 30	7435	7435			4°	
11 30	7435	7435			3°	

MINISTRY OF TRANSPORTATION
AND HIGHWAYS
ENGINEERING & INSPECTION BRANCH
DATE: July 26/82

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Roebuck-Tilbury Loop
Hydrostatic Test Procedure

PIPELINE TEST REPORT - PAGE 3

Test Section ______________
Pipe O.D. ______________
Wall Thickness ______________
Pipe Spec. ______________

24 Hour Proof Test (Log of Pressures and Temperatures)

Dec 9/81

Time (local)	Chart Pressure mPa	Dead-weight Pressure mPa	Temperature °C Fill End	Temperature °C Remote End	Temperature °C Ambient	Remarks
12^{30}	7435	7435			3°	
1^{30} am	7435	7435			3°	
2^{30}	7435	7435			3°	
3^{30}	7435	7435			2°	
4^{30}	7435	7435			2°	
5^{30}	7435	7430			2°	
6^{30}	7435	7430			4°	
7^{30}	7435	7430			4°	
8^{30}	7435	7425			4°	
9^{30}	7435	7425			4°	
10^{30} am	7435	7425			4°	

MOTH

MINISTRY OF TRANSPORTATION AND HIGHWAYS
ENGINEERING & INSPECTION BRANCH
K Kramer
DATE: July 26/82

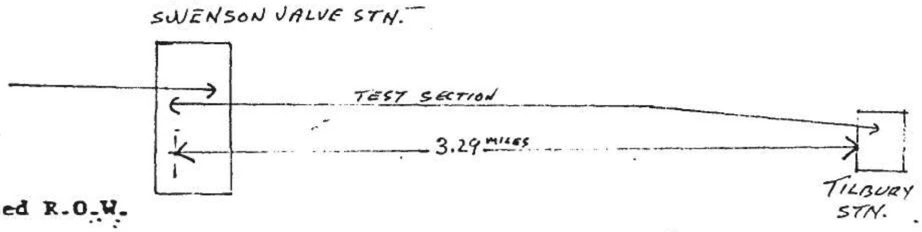
GR58L

INSPECTOR'S PIPELINE REPORT

OMPANY B C HYDRO
ONTRACTOR H&B CONST
NSPECTOR VINCE YUNG
IELD SURREY
ROJECT NO. 3286
LOCATION SWENSON VALVE STN
PRODUCT NAT GAS
ARTIAL PRESSURE OR MOLE PERCENT H_2S

Line No.	Length	Diam.	Wall Thick	Pipe Code	Pipe Grade	Sour Spec.	Exter. Coat.	Inter. Coat.	Depth of Cover	Class Location	Pressure of Weakest El
1	3.29 MILES	36"	.850	Z 245.2	414	—	POLIKEN	EPOXY	30'	III	
2											
3											
4											
5											
6											

soil type DEC 8/81 DWT 7450 Kpa 10:30 AM - CHART ON 10:30 AM
pipe weights CHART READING 7500 KPa
pipe anchors GROUND TEMP. 2.7°C
headers and traps PIPE TEMP - 4.5°C
Right-of-way width DEC 9/81 - DWT - 10:30 AM - 7425 KPa
Valves PIPE TEMP. 4.4°C
Fittings GRD TEMP. 3.0°C
pressure vessels
relief valve
pump
compressor
supports
cathodic protection
test leads
condition of finished R.O.W.



pipeline elevation difference
road crossings
pipeline crossings
railway crossings
utility crossings
river or creek crossings

Piping Tests Date DEC 9/81 Test Medium WATER

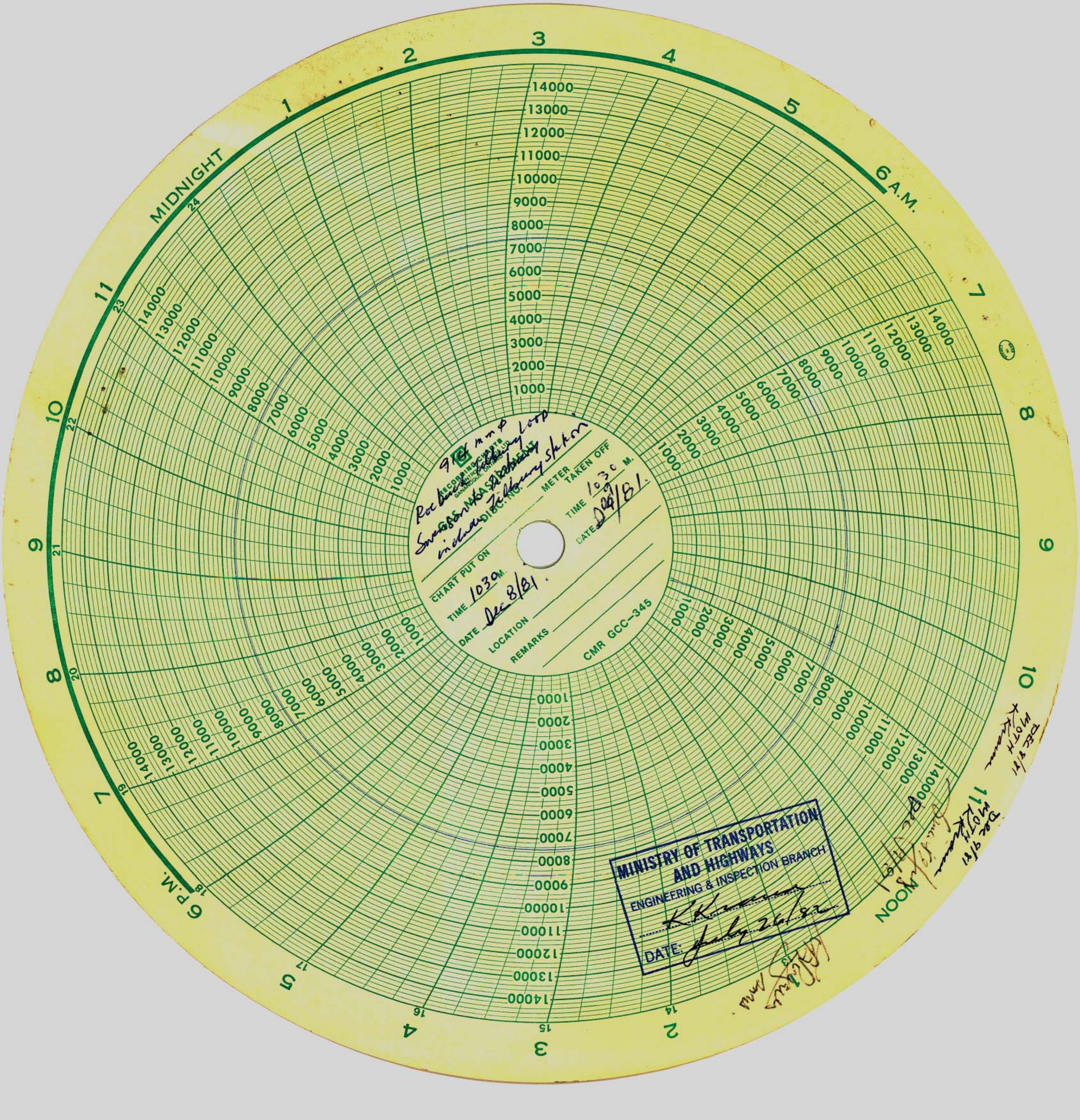
Duration of test 24 HRS (minimum test pressure)

Test Pressure Variation 25 KPa test temperature variation .3°C

Welders: Names	Ticket No.	Class
1.		
2.		
3.		
4.		

Inspected by
Date Dec 8/81

Attachments 1.4b



9164 mmp
Rocback Tilbury Loop
Swanson to Tilbury
include Tilbury station

DISC. NO.

CHART PUT ON
TIME 1030 M.
DATE Dec 8/81.

METER TAKEN OFF
TIME 1030 M.
DATE Dec 9/81.

LOCATION

REMARKS

CMR GCC-345

MINISTRY OF TRANSPORTATION
AND HIGHWAYS
ENGINEERING & INSPECTION BRANCH
K Kr
DATE: July 26/82

Dec 8/81

DEC 8/81
MOTH

DEC 9/81
MOTH

Attachment 1.4c

BC Gas

FAX COVER SHEET

To: Pipeline and Facilities Safety and Engineering Group
Compliance and Enforcement **Branch**
Oil and Gas Commission
200 10003 110 Ave.
Fort St. John BC V1J 6M7

From: J. Lavers. P.Eng
BC Gas Utility Ltd.
Engineering
16705 Fraser Highway
Surrey, British Columbia
Canada V3S 2X7

Bus (604) 592-7745
Fax (604) 592 - 7530

Fax: 250-261-5787

Date: 30/08/02

This message consists of 1 page

Attn: Mr. Richard Caesar. Pipelines/Facilities, Safety & Engr

Subject: Request for **LEAVE TO OPEN**

Pipeline: Alpha/Dominion Site Reinstatement – Heavy Wall Replacements – Delta, B.C.

Certificate # 45-1085

Project # 10707

BC Gas Utility Ltd. requests permission to operate the above noted Pipeline(s).

Parameters for this pipeline test are as follows:

	914 mm OD Replacement (700m)	*610 mm OD Replacement (700m)*
Date Of Test	02-07-17	02-08-10 (
Duration of test	4 hours	4 hours
Minimum Test Pressure	6196 kPa	6468 kPa
Maximum Test Pressure	6202 kPa	6944 kPa
Test Witnessed By	Ken Krause , OGC	Joel Lavers, BCG
M.O.P. requested	4020 kPa	4020 kPa

All applicable charts and as-built data will be forwarded to your office no later than 90 days.

All safety equipment has been tested.

Notification of your approval may be made by return facsimile to 604 - 592-7530

Yours truly,

Joel Lavers, P. Eng
Project Manager

FAXED
08/30/02

Attachment 1.4c

TRANSMISSION PIPELINE VALVE STATION HYDROSTATIC TEST SPECIFICATION

BC Gas

Naturally Resourceful

Alpha-Dominion Site Reinstatement Project

Certificate Number	Project Number	Pre-Test Number	Preparation Date:
-	- P-00032.6.2	-	04/29/02

System Description – NPS 24 / 36 Transmission Pipelines

Location – Alpha-Dominion Site, Delta, BC

Test Equipment Location- Alpha-Dominion Site, Delta, BC

Ref. Drawing # 42010-P-800-300-R0

WBS / I/O # P-00032.6.2

Pipe Specification Data

No	Type	Quantity	Length (m)	OD (mm)	WT (mm)	Grade (MPa)	Factor	Design Pressure (kPa)	MOP (kPa)	Min Test Pressure (kPa)	90% SMYS Pressure (kPa)
1	Pipe	N/A	2.4	914	8.92	414	0.5	4039	4033	5646	7269
2	Pipe	N/A	695.3	914	14.3	448	0.5	7006	4033	5646	12611
1	Pipe	N/A	2.4	610	9.5	483	0.5	7527	4033	5646	13549
2	Pipe	N/A	173.0	610	12.6	483	0.5	9983	4033	5646	17970
3	Pipe	N/A	524.6	610	17.5	414	0.5	11885	4033	5646	21393

Calculated Test Pressures

Elevation Effects	High Point (H)	Test Point	Low Point (h)	ΔP(H) = 49.033 kPa	ΔP(h) = 0.0 kPa
	5.0	0.0	0.0		

Note ; ΔP(H) = 9.8066 x (ΔH); ΔH= (h-htp)

Minimum Specified Test Pressure @ Test Point	OD 914 mm: 5695 OD 610 mm: 5695	(kPa) (kPa)	**Duration:** Below grade – ~~24hrs~~ 4hrs
Maximum Specified Test Pressure @ Test Point	OD 914 mm: 7269 OD 610 mm: 13549	(kPa) (kPa)	

M.E. Bloom EIT	J.E. Lavers P. Eng
Prepared By (Print Name)	**Approved By (Print Name)**
Prepared By (Signature)	**Approved By (Signature)**
Project Engineer, EIT, Engineering Services	**Project Manager, Engineering Services**

Min 5695 H_2O

Max 7300 kPA. 4hrs.

as per Joel. aug 9 '02.

HYDROSTATIC PRESSURE TEST LOG SHEET

Procedure Information

Test Date: JULY 17/02	Test Supervisor:	Work Order Number: P00032.6.2
Test Duration (min) : 4 HRS	Maximum Test Pressure: 7269 kPa	Minimum Test Pressure: 5695 kPa

Test Location: ALPHA DOMINION SITE DELTA B.C.

Instrument Data

Pressure Recorder Serial #. 242 EC-9406156	Temperature Recorder Serial No. SAME
Deadweight Tester Serial # 6101609002	Thermometer Serial # J01004029
Transducer # 1	Pressure Relief Valve Serial #
Transucer Range: 0-3000 PSIG	Pressure Relief Valve Set Pressure:

7.0 Test Data

Test Date (Yr/Mth/Day)	Test Point Readings					Remarks
JULY 17/02	Ddwt.	Recorder Pressure	Recorder Pipe Temp.	Therm. Reading	Amb.	
Time	(kPa)	(kPa)	(°C)	(°C)	(°C)	
Start: 7:10 PM	6196	6200	21	20.2	21.9	
Finsh: 11:08	6202	6200 ~~18.7~~	18.7	18.7	16.8°	

Comments:

WALTER OSADUIK
Recorded By (PRINT Name)

Recorded By (Signature)

INST TECH
Title

BC Gas Supervisor

Ministry Inspector

Attachment 1.4c

Pressure Test Service Form

Date: JULY 17/02

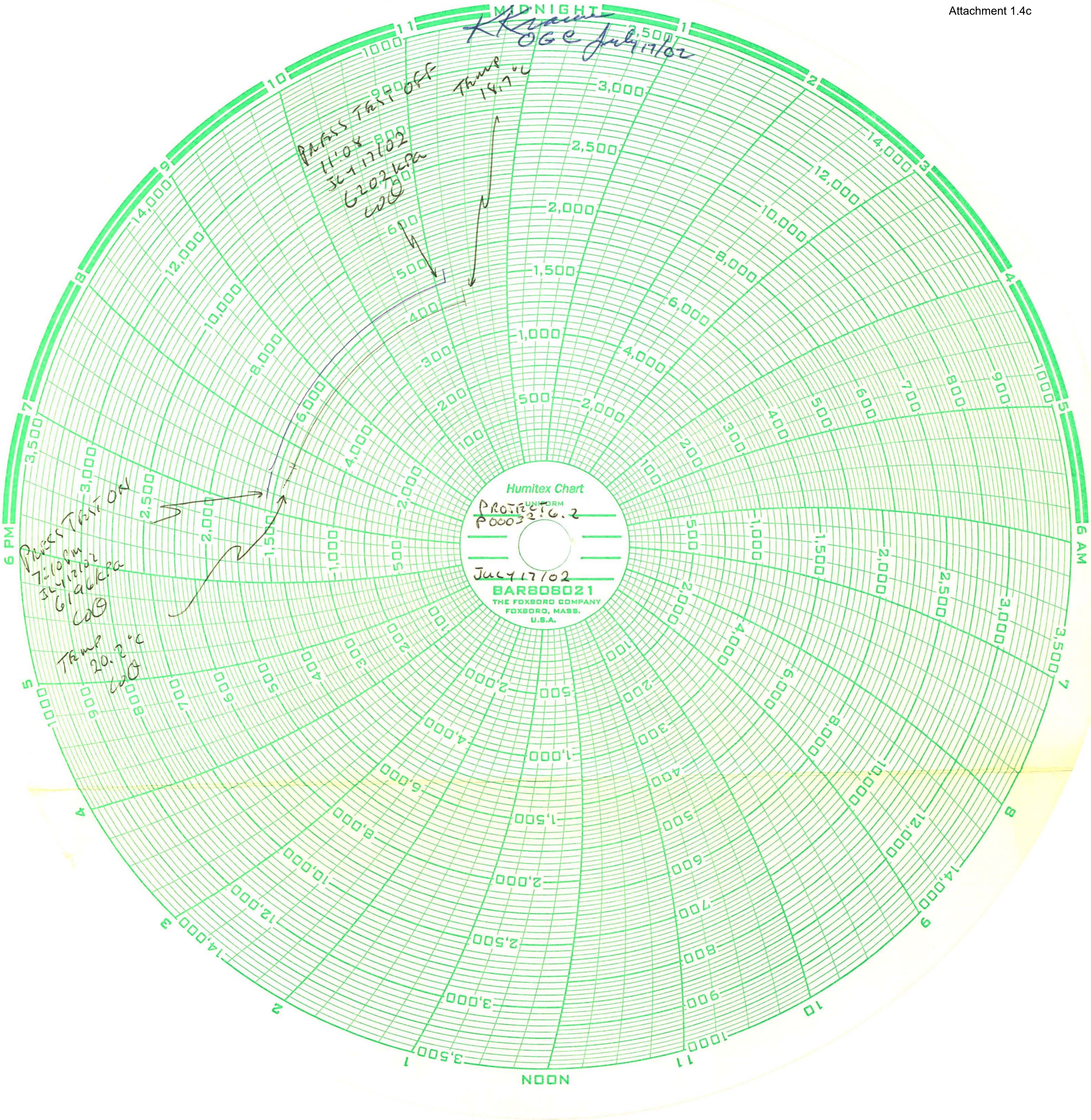
WORK ORDER INFORMATION	**TEST EQUIPMENT**
WO# P00032.6.2	PRESSURE RECORDER # S/N 242EC-9406156 916
LOCATION: ALPHA - DOMINION SITE	TEMPERATURE RECORDER# SAME
DELTA B.C.	
JOB SUPERVISOR: JOEL LAUERS	DWT TESTER # S/N G101609002 15370
	TRANSDUCER # 1
MINIMUM PRESSURE: 5695 KPa	
MAXIMUM PRESSURE: 7269 KPa	TRANSDUCER RANGE: 0 - 3000PSI
TEST MEDIUM: [✓ H2O] N_2	
	THERMOMETER SERIAL # J01004029
MINIMUM DURATION: 4 HRS	

TEST DATA	
START TIME: 7:10 pm	FINISH TIME: 11:10
DWT PRESSURE: 6196	DWT PRESSURE: 6202 kPa
RECORDER PRESSURE: 6200	RECORDER PRESSURE: 6200 kPa
THERMOMETER READING: 20.2 °C	THERMOMETER READING: 18.7 °C
RECORDER TEMPERATURE: 21 °C	RECORDER TEMPERATURE: 18.7 °C

COMMENTS:

Technologist: W

Attachment 1.4c



OGC July 17/02

PRESS TEST OFF
11:08
JLY 17/02
6202 kPa
WO

TEMP
18.7°C

PRESS TEST ON
7:10 PM
JLY 17/02
6196 kPa
WO

TEMP
20.2°C
WO

PROJECT
P00032!6.2

JULY 17/02

Attachment 1.4c

FOXBORO BACK PRINTING NO. 1610

BC Gas

INSTALLATION TEST RECORD

TOWN/CITY: DELTA

LOCATION: ALPHA-DOMINION SITE

Recorder number: 916

Range: 0-14000 KPa

Test Method: ___ Air X Hydrostatic ___ Nitrogen

Weather: WARM, OVERCAST

Job Number: P00032.6.2

Ministry Project Number:

Ministry Certificate Number:

Pipe:	size	length	Pipe:	size	length	Pipe:	size	length
___PE			___PE			___PE		
___ST			___ST			___ST		

Test on

Time 7:10 ___AM ✓PM

020717

Date (yr/mo/day)

Test off

Time 11:10 ___AM ✓PM

020717

Date (yr/mo/day)

Welder/Fuser (PRINT Name):

Certificate/Registration Number:

COMMENTS

PRESSURE/TEMPERATURE RECORDER COMBINED S/N 242EC-9406156

TEMP RANGE -20 TO + 80°C

PRESSURE DWT INSTRUMENT DRUCK DPI610 S/N 6101609002 IS 370

TEMP INSTRUMENT BARNANT LOGR S/N J01004 029 IS 383

DWT TECHNICIAN W. OSADUIK ICS DEPT

I hearby certify that the pipe noted above was installed to current BC Gas Inc. standards and that no leakage was found.

Crew Leader/DMI .... Date (yr/mo/day)

Inspector .... Date (yr/mo/day)

Supervisor .... Date (yr/mo/day)

1610 94/08

arc 3158