INTRODUCTION

We are writing on behalf of the Federation of Rental-housing Providers of Ontario (FRPO) in response to Procedural Order No. 5 in the St. Laurent Pipeline (STLP) Replacement proceeding. This is the second proceeding related to this pipeline, the first being EB-2020-0293.[1] In the first application, FRPO was diligent in its pursuit of understanding the history of maintenance, inspection and condition of the existing pipeline and called for a rejection of the proposed replacement. The Board ultimately rejected the application providing strong recommendations to EGI related to the pipeline.[2] The Board is well aware of the history of this project so we will be efficient in these submissions by drawing on the continued applicability while focusing on the matters at hand and unresolved evidentiary issues.

FRPO respectfully submits that while EGI has implemented some of the Board's recommendations, the evidentiary record of this proceeding includes a significant number of subjective views of the company that EGI has not or will not provide supporting evidence to meet its onus. We believe that it would be in the public interest to order a continued Extensive Inspection and Repair program while substantive evidentiary issues are reconciled, Energy Transition evolution occurs, critical assessment of the EGI's risk conclusions and remedial plans are performed, and infrastructure matters like the TransAlta feed and the relocation of the Rockcliffe Control Station are resolved. We provide our submissions in support of that position below.

[1] FRPO_SUB_EGI ST LAURENT_20220321
[2] EB-2020-0293 dec_order_EGI_20220503_eSigned

ISSUE 1.0 PROJECT NEED

Onus to Demonstrate that Full Replacement is Appropriate has not been Met

EGI's first attempt to receive approval to replace the St. Laurent Pipeline ("STLP") was rejected by the Board. In its decision, the Board cited lack of evidence of risk[3] and unfavourable economics relative to repair/retrofit alternatives.[4] In our view, although the utility has done a better job of investigating and applying in-line inspection to evaluate the pipe, the evidentiary limitations that prompted rejection of the replacement in their first application still exist. While the limitations are different in nature, the utility has not provided a sound evidentiary basis that justifies replacement.

Evaluation of Levels of Risk are Still Subjective

FRPO understands that the generation of risk hierarchies is difficult to quantify fully. When applied, as in this case to a specific pipeline, the initial steps involve facts about the history of the pipe, maintenance records and condition assessments. Notwithstanding EGI's testimony and refusals in the Technical Conference of the first application,[5] robotic in-line inspection (ILI) is feasible and can provide data on the condition of the pipe that informs the current pipe condition. Following the Board's findings in rejecting the initial application, EGI performed ILI on almost 40% of the existing STLP.

The data obtained along with several other factors were combined into a document entitled "Quantitative Risk Assessment (QRA) – St. Laurent North Pipeline.[6] While the Executive Summary asserts *the application of industry standard reliability methods and published failure rates,* its introduction further states that *the quantitative reliability assessment was supplemented with consequences of various outcomes and mapped to the Enbridge Standard Operational Risk Assessment Matrix.*[7] While

[3] EB-2020-0293 Decision and Order, pg. 14-15
[4] EB-2020-0293 Decision and Order, pg. 23-24
[5] Final Transcript EB-2020-0293 EGI LTC TC March 03 2022, pg. 32, line 16 to pg.55, line13
[6] Exhibit B, Tab 1, Schedule 1, Attachment 2
[7] Ibid, pg. 3

FRPO's expertise does not allow a thorough critical assessment of the document, we strived to understand and consider its content through discovery.

The end of the Executive Summary presents EGI's mapping of three types of risks onto the Enbridge Standard Operational Risk Assessment Matrix by coupling the *detailed reliability evaluation … with semi-quantitative consequence assessments.*[8] This aspect—semi-quantitative assessments—signals subjectivity in the establishment of consequences. To try to understand these assessments, we tried to understand the practical effect on the matrix of the EGI's repair of the one feature of the STLP that required emergency repair.

In its pre-filed evidence, EGI provided a memo to the Board regarding an integrity feature that represented a material safety concern determined by the robotic inspection tool.[9] Further, EGI laid out a plan to install a by-pass of that section of pipe to allow a decommissioning of section to reduce the associated risk. In our respectful submission, the discovery of this feature and prioritized mitigation is why FRPO initially inquired[10] and recommended the company's use of ILI[11] and why ratepayers see the Enhanced Distribution Integrity Management Program as a good investment.[12]

To understand the Risk Matrix, given that amongst the 4.5 km of pipe in-line inspected with this feature being the only finding that prompted an expedited mitigation, we asked about the finding and repair's impact on Risk Matrix Assessment. The Risk Matrix in the Executive Summary of the QRA depicts three operational conditions for their Likelihood and Consequence:

- F1: Small Leak resulting in pipeline repair/replacement
- OD: Customer losses due to operational disruptions
- HS2: Local ignition at failure site

[8] Ibid, pg. 7
[9] Exhibit B, Tab 1, Schedule 1, Attachment 1
[10] Final Transcript EB-2020-0293 EGI LTC TC March 03 2022, pg. 32, line 16 to pg. 55, line 13
[11] FRPO_SUB_EGI ST LAURENT_20220321, pg. 6-9
[12] EB-2020-0200, EGI_SettlementP_2024 Rebasing_20230713, pg. 31 & 56

The assessment generates polygons mapped onto the Risk Matrix. EGI's response to our interrogatory provided these depictions before and after the repair. [13] It is noteworthy that this section was potentially most likely and consequential of all findings from the ILI. Given the incredible similarities of the before and after matrices for the three operation conditions outlined above, we sought clarity in the Technical Conference. EGI witnesses confirmed that although the two matrices appeared very similar, there was an almost imperceptible difference due to the logarithmic scale and the number of features eliminated relative to the total.[14]

Our concern from this enhanced understanding is that these assessments, while containing some levels of quantification, are still prone to subjectivity in a manner that is hard to de-construct. Said more simply, if a utility examines about 40% of a pipeline using the most enhanced technology that it has applied to its distribution system, found and repaired the one substantial threat and its assessment of risk moves almost imperceptibly, one must question the practical utilization of this assessment in driving decisions in the order of hundreds of millions of dollars. In our view, the company's rating of risk generated by this approach is not determinative evidence of an urgency to replace the pipeline. This is not only our opinion but seems to be shared by DNV as outlined below in response to our inquiry regarding their recommendation of "*more detailed consequence estimation than currently evaluated*" included in their recommendation:[15]

> *The current approach to the consequence estimation has not evaluated specific release scenarios with modeling, but instead generically assumed that a release event would result in either 0.5 (minimum) to 10 (maximum) people impacted and applied the estimate to all locations along the pipeline. A "more detailed consequence estimation" would entail evaluating specific release scenarios from the pipeline at specific release locations and performing consequence hazard modeling of the release scenarios to understand the potential extent of the*

[13] Exhibit I-FRPO-10, pg. 2
[14] REDACTED PUBLIC Final Transcript for EB-2024-0200 Technical Conference October 30 2024, pg. 92, line 25 to pg.96, line 8
[15] Exhibit B, Tab 1, Schedule 1, Attachment 3

> *flammable hazard zones and evaluate the potential impacted locations and potential number of people impacted based on population density estimates.*[16]

In our view, this response demonstrates the limitations of the EGI approach which the company is asking the Board to be considered determinative of risk. We respectfully submit that EGI's QRA is a step in the right direction, but Ontario would benefit from additional development of the approach, aided by experts, before investing hundreds of millions of dollars with other factors creating uncertainty.

Evaluation of Risk Levels and Proposed Replacement Lacks Critical Review

Recognizing our limitations with expertise in all elements of risk assessment, especially across multiple jurisdictions, FRPO strived to get DNV's views. DNV was engaged by EGI as *an international consulting firm renowned as an industry leader in quantitative risk assessments to conduct an in-depth evaluation of the reliability and risk assessment methodologies applied in the QRA.*[17] The only evidence provided by DNV was a 1.5 page memo endorsing the process and agreeing that "*additional remedial action to improve the reliability of 8.8 km of the pipeline should be considered*"[18], which is equivalent to about 75% of the pipeline.

Given this endorsement, by way of interrogatory, FRPO requested a prioritized list of recommended remedial actions that could improve the reliability of that section of the pipeline. EGI did not provide DNV's response asserting that the assessment of potential remedial actions falls outside the scope of DNV's engagement.[19] Lacking any other source of critical review and trying to understand what DNV would include in the remedial actions, we pursued our request for DNV's views in the Technical Conference, but our request was refused.[20]

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[16] Exhibit I-FRPO-18, pg. 2
[17] Exhibit B, Tab 1, Schedule 1, Appendix B, pg. 9
[18] Exhibit B, Tab 1, Schedule 1, Attachment 3, pg. 1
[19] Exhibit I-FRPO-17
[20] REDACTED PUBLIC Final Transcript for EB-2024-0200 Technical Conference October 30, 2024, pg.96, line 8 to pg.98, line 23

In our experience, additional remedial actions include many strategies of protection, monitoring and inspection to develop a program to mitigate risks. FRPO was trying to assist the Board with the views of a renowned expert on the potential paths to mitigate risks on the pipeline. EGI's refusal to engage DNV on this request creates significant alarms in terms of the reliability of EGI's proposal that the "best" mitigation of the risks is replacing the pipe. We understand that the production of a plan for remedial action was not part of EGI's engagement of DNV but we respectfully submit that it ought to have been. However, the company's provided reason, included below, does not withstand scrutiny:[21]

MR. QUINN: No. Based upon their experience, and based on what they've read what would they recommend as the first steps of that remedial action?

MR. KEIZER: No. It is not a question we are going to be asking them, and it's, quite frankly, it is beyond the scope of their expertise. The question is appropriately answered by Enbridge in this interrogatory.

Contrary to the assertion that recommending remedial action is beyond their expertise, we offer to the Board that amongst the services provided by DNV is their software, Synergi Pipeline, that among other features provides "*threat assessment and configured risk models to provide expert remedial advice*".[22] Given the technical content of the QRA evidence produced by EGI, the Board would have benefited from DNV's views on what they would consider as *remedial action*.

Without understanding what DNV's experience would recommend, the Board is left only with the company's recommendation which is unsupported by any independent expert. Their unwillingness to engage DNV in their expert views on remedial actions in support of the EGI proposal is telling. In our respectful submission, the existing record and its

[21] UNREDACTED CONFIDENTIAL Final Transcript for EB-2024-0200 Technical Conference October 30, 2024, pg. 98, lines 1-7
[22] https://www.dnv.com.au/services/software-for-gas-distribution-networks-synergi-pipeline-1392/

omissions has not met EGI's onus of complete evidence in support of its proposed replacement.

ISSUE 2.0 PROJECT ALTERNATIVES

Extensive Inspection and Repair Provides Measured Response to Risk & Uncertainty

EGI outlines the various alternatives the company has considered to mitigate risks on sections of the pipeline.[23] While our focus was on the assessment of risk and approaches to reducing the size of a replacement pipeline (addressed below), in reviewing the record, FRPO respectfully submits that the best alternative, for such a time as this, is Alternatives 3 or 4 with input provided by DNV. While we normally would expect that EGI would seek a competitive RFP, DNV is now intimately aware of the process EGI has undertaken. With our understanding of DNV's capabilities, they could assist EGI with a measured approach to not only advise on ongoing inspection and risk assessment of the pipeline but also to assist with the prioritization of remedial actions that the Board has not been able to hear to this point.[24] In addition, with what is learned and reported to the Board, ratepayers would benefit from the opportunity to inform the investments made through the Enhanced Distribution Integrity Management Program in their applicability to other EGI infrastructure.

FRPO believes the Extensive Inspection and Repair would be the most appropriate investment for ratepayers. Through our collaboration with other intervenors, we have received and reviewed a draft of the submissions of the School Energy Coalition (SEC). We adopt the SEC analysis of the economics of the alternatives which aligns with our recommendation of a measured approach. Further, by taking this measured approach issues associated with the TransAlta feed and the Rockcliffe Control Station can be resolved to avoided unutilized capacity and, potentially, replacing the Sandpoint segment twice.

[23] Exhibit C, Tab 1, Schedule 1, Table 1, pg. 3-5
[24] UNREDACTED CONFIDENTIAL Final Transcript for EB-2024-0200 Technical Conference October 30, 2024, pg. 98, lines 1-23

EGI Evidence on TransAlta Feed and Implications Warrants more than Change Request

Incremental to the initial application, EGI has proposed, tentatively, an additional 660m segment of XHP extending south from the initial proposed replacement NPS 16 pipe to feed TransAlta.[25] The feed to TransAlta was installed in 1990 so the pipe installed at that time should be in superior condition to the rest of the STLP. In the pre-filed evidence, EGI stated that they were currently assessing three alternatives to replace that segment. We asked about this new wrinkle to STLP project in the Technical Conference and the witnesses could not answer some fundamental questions about the proposal and what, in fact, the Company was asking the Board to approve.[26] After extensive dialogue, the requested undertaking provided costing for the alternatives but a series of unresolved issues yet to be determined.[27]

FRPO has two concerns about this:

1) For either of the longer pipeline solutions, gas for TransAlta would have to travel north from Ottawa Gate North on the 470 psig line past the TransAlta take-off near Industrial Ave. to the St. Laurent Control Station. Then the gas for TransAlta would have to be fed by the proposed NPS 16 going south before entering the newly proposed pipe back to Industrial Rd. In our view, a simple understanding of this proposal conjures up what a waste of pipe capacity and associated cost. At this point, it is completely opaque whether these capacity costs (or conversely excess capacity if the station alternative is chosen) are being considered in the determination of preferred alternative for the TransAlta feed.
2) If the project is approved as applied for and EGI determines the more economically reasonable choice of the station alternative, some of NPS 16 capacity that was for TransAlta would be excess capacity for STLP. Said differently, the pipe sizing for the STLP would be unnecessarily over-built for the

[25] Exhibit D, Tab 1, Schedule 1, pg. 4-8
[26] UNREDACTED CONFIDENTIAL Final Transcript for EB-2024-0200 Technical Conference October 30, 2024, pg. 85, line 22 to pg. 92 line 5
[27] Exhibit JT1.18

forecasted demands. This over-build relative to demand would be occurring as the City is striving to reduce demand for natural gas.[28]

In our view, a decision on the alternative to serve TransAlta ought to be made before the sizing any replacement of STLP is finalized. However, EGI has indicated that it would only "*file any necessary update or notice of change*" to advise the Board. But that order of events would leave the extra capacity already installed if the application is approved as filed.

<u>Relocation of the Rockcliffe Control Station Presents Opportunity to Reduce Cost</u>

Another example of the application's lack of readiness for approval is the potential relocation of the Rockcliffe Control Station. This station is the end of the STLP that controls the pressure to 1210 kPa (175 psig) for delivery under the Ottawa River to Gazifere. However, the current pressure reducing equipment at Rockcliffe requires a differential above the delivery pressure making the minimum inlet 1400 kPa (200 psig).[29] FRPO explored the opportunity to reduce that differential if the station was going to be relocated.[30] We specifically asked if the use of control valves instead of pressure regulators could reduce the differential required. EGI confirmed that, in fact, they had completed the preliminary design using control valves due considerations of noise, footprint limitations, and minimizing pressure differentials at a high-level incremental cost of $500,000.[31]

This marginal decrease in minimum inlet, together with potential reduced capacity requirement by serving TransAlta more effectively with the addition of a station, would reduce the sizing of a proposed replacement pipeline. The challenge at this time is EGI cannot provide the Board with definitive plans for either of these changes. In our view, the proposed replacement has too many uncertainties in design to ensure that the project is not over-built if approved. Further, if the gaps in evidence on the two issues

[28] SEC_CityEvidencePackage_EGI_St Laurent_20220117
[29] EB-2020-0293 Exhibit I.M.2.FRPO.29
[30] UNREDACTED CONFIDENTIAL Final Transcript for EB-2024-0200 Technical Conference October 30, 2024, pg. 162, line 16 to pg. 164 line 16
[31] Exhibit JTX1.29

below (Gazifere interruptible service and system operation limitations) are combined with more efficient service to TransAlta and to Gazifere through the new Rockcliffe Control Station, a substantial adjustment could be made if over some time of Extensive Inspection and Repair do not mitigate risks sufficiently.

EGI has not Clarified nor Optimized its Deliveries to Gazifere

In proposing the complete replacement and upsizing of the existing STLP, EGI did not file any evidence of considerations regarding minimizing the size of the pipeline by optimizing deliveries to its affiliate company, Gazifere. Gazifere is fed by both the STLP and a larger sized pipe to the east (referred to as the Eastern feed in the Technical Conference). Given that EGI provides network analysis services to Gazifere,[32] it is uniquely qualified to optimize deliveries to maintain firm contractual requirements while minimizing the size and cost of the STLP. However, the company was unwilling to pursue discussions with Gazifere to reduce the demand on the STLP.[33]

However, there is a critical opportunity for which we have no explanation. As the Board knows through correspondence requesting more complete answers, FRPO pursued a more complete understanding of the demand requirements of the Gazifere contract.[34] At the outset of the confidential portion of the technical conference, FRPO sought to clarify how the design demands at the Rockcliffe control point on the St. Laurent pipeline were determined, including the treatment of interruptible service in the contract. The dialogue revealed discrepancies in the daily firm contracted demand, which were not adequately addressed in the updated responses. The firm contracted hourly demand of 62,600 m^3/hr does not reconcile with the 88,800 m^3/hr stated as the design hour demand. This 40% incremental demand discrepancy has significant implications for pipe sizing and cost allocation.

[32] UNREDACTED CONFIDENTIAL Final Transcript for EB-2024-0200 Technical Conference October 30, 2024, pg. 138, lines 14-19
[33] UNREDACTED CONFIDENTIAL Final Transcript for EB-2024-0200 Technical Conference October 30, 2024, pg. 141-142
[34] UNREDACTED CONFIDENTIAL Final Transcript for EB-2024-0200 Technical Conference October 30, 2024, pg. 127, line 17 to pg. 128, line 14

In response to FRPO's initial request for more fulsome responses,[35] the updated response simply states:[36]

> *The demand and flows that are represented in the evidence and subsequent interrogatories are the result of demand modelling at design conditions with interruptible flow off, and not the application of a contract volume. The design condition for the system in Ottawa and Gazifère does not include interruptible flow.*

The updated response does not reconcile the firm contracted hourly demand of 62,600 m3/hr with the 88,800 m3/hr sent to Gazifere in EGI's design. The more than 40% incremental demand would have a substantial effect on pipe sizing for this project. As a result of no reconciliation of the difference in the updated response, our requested simulation,[37] including the simulation requested later,[38] are not performed nor reported on for the Board's understanding.

Without the benefit of a hearing, this clear evidentiary conflict is still unresolved. EGI understands the clarification that we are seeking but, to this point, has chosen not to clarify. We respectfully request that EGI provide a clear explanation in their reply argument so that the Board can consider whether EGI has met its obligation to minimize costs appropriately in its consideration of alternatives.

Further, EGI has evidenced that they may seek an ICM if the project is approved and it qualifies.[39] In our view, this evidentiary conflict would be an issue if this path is chosen. Moreover, the question of the appropriate contribution of Gazifere should be considered as part of that issue. Further, the appropriate contribution of Gazifere may be heard as part of Phase 3 of the rebasing proceeding later this year.

[35] FRPO_EGI_REQ_FULSOME RESP_LTC ST LAURENT_20241129
[36] Exhibit JTX1.22 Updated
[37] Exhibit JTX1.26 Updated
[38] Exhibit JTX1.29 Updated
[39] Exhibit A, Tab 2, Schedule 2, pg. 8

EGI has not Explained the Nature of the Limitations Cited in Optimizing its System

EGI has not demonstrated that optimized system operation has been assessed. During the technical conference, we discussed the possibility of raising and lowering pressures at various stations to reduce demand on the St. Laurent pipeline. During the dialogue in the Technical Conference, there was no limitation of 380 kPa cited when the undertaking was accepted. EGI's response, however, did not provide any evidence to support their assertion that increasing the operating pressure above 380 kPa is not possible. This lack of evidence leaves the Board without a clear understanding of any real constraints and potential solutions.

Lacking EGI's explanation of why it has imposed an artificial cap of 380 kPa on the system, we can only speculate that by keeping the maximum system pressure under the maximum allowable operating pressure, EGI has contingency to add additional load in the short term prior to infrastructure enhancements to address the additional load as utilities have done historically. However, with the Ottawa system growth geographically constrained by the Ottawa River and the municipalities efforts toward reducing its carbon emissions, no contingency should be needed.

With the backdrop of energy transition, it should be incumbent upon the utility to consider and implement solutions with this in mind—even if it means evolving operating practices that were developed over the previous decades of expected growth. In this case, EGI cannot deny that with the investment of tens of thousands (not millions) of dollars in regulators and associated equipment of stations on the west side of the system could be providing higher pressures to the system, while stations fed by STLP could be providing less and likely reducing the size of a replacement pipeline as an economic alternative.

Instead, EGI answered our follow-up inquiry to their committed undertaking by using hyperbolic phrasing asserting that increasing the pressure above 380 kPa was not possible.[40] That statement is categorically untrue and, in our respectful submission, the

[40] _EGI_EB-2024-0200_Updated Undertakings_20241206_Redacted, Exhibit JTX1.28

Board should be concerned when the utility assertions are made without a shred of evidence. FRPO pushed back against that statement using facts from our knowledge of these systems and the safety code CSA Z662.[41] In its response, EGI stated "*increasing the maximum set pressure to above 380 kPa as suggested by FRPO is not possible as a practical matter for a number of reasons including: regulator operating requirements; overpressure protection and historical system operations.*[42]

We will respond simply to each of these "reasons":

- Regulator operating requirements: Regulators come with a variety of characteristics in terms of output pressure precision and are equipped with springs that have ranges of outlet pressure capability. In simple terms, if the output pressure variability is a concern, a utility changes the regulator to one that is more precise. If the regulator has the required precision but is bounded by the range of pressure available by the current spring, the utility changes the spring. These might "*practical*" limitations of stations at this point but each of these limitations could be overcome by hundreds or perhaps thousands of dollars.
- Over pressure protection: The Code Z662 requires that the station have sufficient over pressure protection such that no one incident would cause the pressure in the system to exceed 10% of the operating pressure. Each station would already have that capability independent of the setting of the output pressure of the station as long as the setting was 420 kPa or less. If the regulator needed to be changed, then the over pressure protection may need to be upgraded but that situation would be rare if the regulator were selected with the over pressure requirement in mind as an experienced station engineer would do.
- Historical system operations: As noted above, utilities often capped their operational set pressure below the maximum operating pressure of the system. This was often done to have a contingency to allow for growth allowing time for system reinforcement. As noted previously, historical approaches should be

[41] FRPO_SUB_EGI UPD UNDERTAKINGS_CONF_20241212
[42] _EGI_EB-2024-0200_Updated Undertaking_20241213. Exhibit JTX1.28

questioned in a time of energy transition particularly in a system that has it growth limited by geography, in this case, the Ottawa River.

While the above dissection of EGI's response would have been better handled in a Technical Conference, EGI did not bring up these concerns when they accepted the undertaking to test the effect of increasing the pressure on some stations while reducing the pressure on the stations fed by the STLP.

EGI stated that these adjustments *"would not be sufficient in order to meet the required demand reduction on the St. Laurent Pipeline to affect a reduction in pipe size"*. If that were the case, one would ask why that was not shown with evidence of the flows and pressures. The utility could have added its caveats about the limitations of possible but that was not done. In essence, these station adjustments are an Integrated Resource Planning (IRP) alternative that can reduce infrastructure investment. Testing these approaches is essential especially when the usefulness of the new facilities may not see the end of their economic life.

It is one thing for the utility to have information asymmetry in many of these matters. However, when interested parties ask the utility for information on primarily financial matters, some of that barrier may be overcome. In recent years, more and more, parties are asking for the spreadsheets so that the formulae and assumptions can be understood in context. These spreadsheets can also be used to test different inputs to consider alternatives not proposed by the utility.

On the other hand, in system operation, the utility maintains a complex model that is designed to use linear programming and iterative algorithms to determine the impact to the system operation of a change. These models are proprietary and cannot be "transferred" to a party to test their hypothesis. That testing must be done by the utility by accepting the request and faithfully carrying it out. This formidable barrier has arisen in a number of recent applications and warrants consideration by the Board.

For the purposes of this application, EGI has not been willing to test the hypotheses advanced by FRPO resulting in the Board being under-informed on opportunities.

CONCLUSION

In FRPO's respectful submission, EGI has not met the onus of sufficient evidence that its proposed replacement of the STLP is in the public interest. Instead, we submit that Extensive Inspection and Repair is the measured approach. We would further recommend that EGI be directed to produce a report in the next two to three years with the support of DNV to implement the Inspection and Repair program while refining the development of the risk matrix.

We believe that this approach will have additional benefit to inform the Enhanced Distribution Integrity Management Program. Further, if after sufficient implementation and learning, the utility believes that identified and quantified risks create the need to replace sections of the pipe, some of the uncertainties described above and related to Energy Transition will inform appropriate sizing of the replacement section.

COSTS

In this proceeding, FRPO was assisted by and worked with other parties to develop a shared understanding of the issues and concerns with this project. In spite of challenges with obtaining requested technical information cited above, we strived to provide the Board with our experience that would be helpful in assessing the application and determining what is in the public interest. As a result, we respectfully request the award of 100% of our reasonably incurred costs at such time as the Board calls for those costs.

ALL OF WHICH IS RESPECTFULLY SUBMITTED ON BEHALF OF FRPO,

Dwayne R. Quinn
Principal
DR QUINN & ASSOCIATES LTD.