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File No. 61604.51

December 14, 2023

BY EMAIL and RESS
registrar@oeb.ca

Ms. Nancy Marconi
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Marconi:

Re: Enbridge Gas Inc. ("EGI") Panhandle Regional Expansion Project ("Panhandle Project") (EB-2022-0157) ("Proceeding")
Submission of the Association of Power Producers of Ontario ("APPrO")

Please find enclosed the submission of APPrO in the above-noted Proceeding.

Yours truly,

BORDEN LADNER GERVAIS LLP

J Vellone

John Vellone

JV/CB

EB-2022-0157

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B, and in particular, sections 90(1) and 97 thereof;

AND IN THE MATTER OF an Application by Enbridge Gas Inc., for an Order or Orders granting leave to construct natural gas pipelines in the Municipality of Chatham-Kent and Essex County;

AND IN THE MATTER OF an Application by Enbridge Gas Inc., for an Order or Orders approving the proposed forms of pipeline easement and temporary land agreements.

SUBMISSIONS OF THE ASSOCIATION OF POWER PRODUCERS OF ONTARIO

December 14, 2023

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I. INTRODUCTION

1. This is the written submissions of the Association of Power Producers of Ontario ("**APPrO**") in respect of an application filed by Enbridge Gas Inc. ("**Enbridge**") for leave-to-construct the Panhandle Regional Expansion Project (the "**Project**") and related approvals (the "**Application**").

2. APPrO's members operate at the nexus between Ontario's natural gas system and Ontario's electricity system. Its members include almost the entire Ontario natural gas-fired electricity generation fleet operating in the IESO-Administered Market ("**IAM**"): about 9,000 MW of installed natural gas-fired generation – or about 90% of total transmission connected gas-fired generation in operation today. APPrO members are also participating in the IESO's recent procurements for gas-fired generation to meet resource adequacy and reliability requirements for the province's electricity grid.

3. APPrO has coordinated its participation in the Application with Atura Power in an effort to streamline its intervention, avoid duplication and facilitate efficiency in the hearing process. In this context, APPrO has had an opportunity to review the Atura Power submissions in respect of the Application. APPrO supports those submissions without reservation.

II. EXECUTIVE SUMMARY

4. APPrO agrees with Enbridge that the Project is in the public interest and that the relief requested in the Application should be granted for the following reasons, which are expanded upon below:[1]

   a) The OEB's current Letter of Direction emphasizes that regulatory certainty is imperative to continued economic investment in the province;

   b) The Project is clearly a transmission project on the facts and E.B.O. 134 applies;

   c) A CIAC is not appropriate for the Project;

[1] Enbridge AIC at paras 2-3.

d) The Project is needed to meet both gas and electricity demand in the Panhandle region;

e) The Project is the best alternative to meet the identified need; and

f) The Project meets the E.B.O. 134 economic test at both stage 2 and stage 3 and is in the public interest.

5. This Application also raises fundamental questions of fairness as between two different groups:

- Existing customers that have benefitted from gas transmission system expansion projects since 1987 under the E.B.O. 134 framework, without an obligation to make any contributions in aid of construction ("**CIACs**") (collectively, the "**Incumbent Consumers**"); and

- Incremental customers who, for the first time in 36 years, are faced with the risk of having to make a CIAC for a transmission system expansion project despite compelling evidence based on the Stage 2 and Stage 3 benefits, that the Project is in the public interest (the "**Incremental Consumers**").

6. Several intervenors in this proceeding who represent the interests of the Incumbent Consumers only, for reasons that are unclear to APPrO, are likely to advocate strongly that the OEB should modify or discard entirely the existing E.B.O. 134 framework for this Project.

7. As one of the only intervenors in this proceeding that can credibly claim to represent the interests of both Incumbent Consumers and Incremental Consumers, APPrO submits the OEB should deny such requests since this is not the appropriate forum to revise E.B.O. 134, a CIAC is not justified and the OEB has already determined that issues of cost allocation are to be decided as part of Enbridge's cost of service application.

III. THE IMPERATIVE OF MAINTAINING REGULATORY CERTAINTY AND PREDICTABILITY

8. Regulatory certainty and predictability in Ontario Energy Board (the "**OEB**") decision making is essential to APPrO's members when operating their respective businesses. This need for certainty is highlighted in the Ministry of Energy's Letter of Direction to the OEB on November 29, 2023:[2]

> "…it is critical that the OEB ensures that Ontario's electricity and gas transmission and distribution systems are built to support these goals in a timely manner, while protecting ratepayers. Achieving this goal requires timely decision-making, well scrutinized costs and **a regulatory environment with certainty for proponents**. […] I also ask the OEB to keep in mind the impact that delays and uncertainty can have on Ontario families, businesses and Indigenous communities, as well as economic investment in the province. […] The OEB should continue to ensure that the needs of all customers are considered in its work, and that access to electricity and natural gas in an affordable manner remains central to decision-making."

9. Regulatory certainty is particularly important now, as the IESO moves forward with multiple procurements to meet emerging energy and capacity needs that will require new assets to be built and the continuing operating of existing assets. Regulatory uncertainty that undermines investment in the province will have an impact on the reliability of the province's electricity grid.

10. Indeed, maintaining regulatory certain and predictability is the primary way the OEB fulfills its statutory mandate to promote economic efficiency and cost effectiveness in the generation of electricity and to facilitate the maintenance of a financially viable electricity industry.[3]

[2] Ministry of Energy, Letter of Direction, November 29, 2023, online: <https://www.oeb.ca/sites/default/files/letter-of-direction-from-the-Minister-of-Energy-20231129.pdf>
[3] Subsection 1(1)2. of the *Ontario Energy Board Act, 1998.*

11. It is APPrO's understanding that Enbridge would require a $150 million CIAC to achieve a 0.8 PI for the Project.[4]

12. We recognize that Enbridge is unable to allocate this CIAC amount among customers due to unique features of its natural gas transmission system and the looped function of the new NPS 36 pipeline. We agree with Enbridge's rationale in this regard.

13. For the purposes of these submissions, and the ease of use of round numbers, we have assumed that (were CIACs required) power generators would be required to pay just over approximately 1/2 of this CIAC – a total of approximately $80 million equally split between each incremental generator - $40 million each. For clarity, this figure is only meant for the purposes of illustrating the potential scale of CIAC impact but in no way reflective of any modelling or other means of cost allocation. APPrO supports Enbridge's view that it is virtually impossible to fairly or accurately calculate a CIAC.[5]

14. The evidence in the Application is that two natural gas-fired electricity generators will benefit from the Project: (a) the Brighton Beach Generating Station (the "**Brighton Beach GS**");[6] and (b) the East Windsor Cogeneration Centre (the "**East Windsor GS**").[7]

15. Both of these electricity generation facilities are existing, captive customers of the Enbridge natural gas system. They cannot move to a different location or jurisdiction if the Project is not approved or if CIACs are required. The evidence is that each generator is already party to legally binding obligations to provide capacity and energy to the IESO.

16. Specifically, the Brighton Beach GS is an existing natural gas-fired electricity generator owned and operated by Atura Power. The existing IESO contract for Brighton Beach is due to expire in 2024, and accordingly, pursuant to a directive issued by the Minister of Energy

[4] Exhibit J2.1.
[5] Transcript V2, P8, L25-28
[6] Exhibit B, Tab 1, Schedule 1 at para. 59.
[7] Exhibit B, Tab 1, Schedule 1, at para. 60.

on April 27, 2023,[8] the Brighton Beach GS was recontracted by the IESO to provide approx. 540 MW of capacity with a term ending July 15, 2034.[9]

17. Exhibit X of the Brighton Beach Clean Energy Supply (CES) Contract (the "**PREP Exhibit**") was filed on the evidentiary record in this proceeding by SEC.[10] It demonstrates the dependence of the Brighton Beach GS on the outcome of this proceeding. Notably, the PREP Exhibit allocates 60% of any CIAC to the IESO, with the remaining 40% to be borne by the generator.

18. Notably, 40% of $40 million is still a jaw dropping $16 million of unforecasted and unforeseen costs.

19. Will the Brighton Beach GS continue to be financially viable if it must fund 40% of a CIAC? As explained by Mr. Macpherson, it would be "very commercially adverse".[11]

20. The East Windsor GS is an approximately 106 MW expansion project that was successfully bid by Capital Power Corporation into the IESO's E-LT1 RFP process.[12] It is subject to a standard form of Expedited Long-Term Reliability Services (E-LT 1) Contract with the IESO (an "**E-LT1 Contract**"), the form of which is publicly available.[13]

21. There is nothing similar to the PREP Exhibit in the E-LT1 Contract. Under the E-LT1 Contract, any unexpected CIACs would have to be funded 100% by the generator. In addition, the E-LT1 Contract does include a Must-Offer Obligation which makes the generator legally obligated to deliver on incremental capacity.

22. Under our assumptions, that is $40 million of unforecasted and unforeseen costs.

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[8] https://www.ontario.ca/page/directive-order-council-5862023
[9] Clean Energy Supply (CES) Contract between Brighton Beach Power L.P. and the Independent Electricity System Operator dated April 27, 2023 (available online at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/energy-procurement/Brighton-Beach/BBGS-CES-Contract.ashx).
[10] Exhibit K2.5 SEC Prep Hearing Compendium at pages 56-58.
[11] Transcript Volume 2 at page 192, line 20 to page 193, line 8.
[12] See page 3 of the IESO's published list of E-LT1 RFP Selected Proponents issued September 17, 2023 (available online at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/long-term-rfp/ELT1-RFP-Selected-Proponents.ashx).
[13] The E-LT1 Contract is available online at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/long-term-rfp/E-LT1-Contract-incorporating-Addenda-20230203.ashx

23. Would the East Windsor GS be financially viable if it had to fund 100% of a CIAC? Again, it would be very commercially adverse.

24. Whether bidding into competitive IESO RFP processes (like the East Windsor GS) or when negotiating bilateral power purchase agreements (like the Brighton Beach GS), APPrO members rely on regulatory predictability and certainty in the OEB's decisions in order to make significant investment decisions that benefit all Ontario electricity consumers and ratepayers.

25. This is because natural gas-fired electricity generators that must forecast their fixed costs into their bids (including any CIACs), which were submitted in February 2023, and are subsequently contractually held by the IESO to those fixed cost forecasts. Unforeseen costs due to regulatory uncertainty either result in higher contracted costs for electricity ratepayers or the inability to build new generating capacity to meet the province's emerging electricity needs, which results in broader economic loss across Ontario.

26. Generators rely on the OEB to continue to apply its E.B.O. 134 economic test, in a manner consistent with past decisions since 1987. This means Enbridge's Project costs are not allocated to end-use customers and customers are not required to provide a CIAC to improve Stage 1 economics.

27. A decision by the OEB in this Application not to apply its E.B.O. 134 economic test for transmission upgrades, or to amend the E.B.O. 134 require end-use customers to pay CIACs to improve Stage 1 economics, would, in APPrO's submissions, not be consistent with the OEB's statutory obligation to (a) promote economic efficiency and cost effectiveness in the generation of electricity; and (b) facilitate the maintenance of a financially viable electricity industry.

IV. E.B.O. 134 IS THE PROPER ECONOMIC TEST FOR THE PROJECT

28. APPrO agrees with Enbridge that E.B.O. 134 is the appropriate economic test to apply to the Project, as the Project consists entirely of transmission pipeline infrastructure to which distribution customers do not directly connect.[14]

29. The Project is akin to the transmission "trunk" of a tree that serves many smaller "branches" of the distribution system.[15] The characteristics of the Project support a transmission designation and use of E.B.O. 134, particularly the Project will:

    a) relieve a bottleneck in the Panhandle transmission system to provide more capacity to serve a broad geographic area where a number of customers will benefit;[16]

    b) allow any customer within the geographic area to use the additional capacity on a "first-come, first-served" basis;[17]

    c) benefit large-volume customers who have not yet been identified. For example, an unanticipated industrial gas user requested service in 2021 for the proposed NextStar battery plant (joint venture between LG and Stellantis) and consumed a significant proportion of existing capacity on the Panhandle system without paying a contribution in aid of construction ("**CIAC**");[18]

    d) be a pipeline "loop", meaning that it will parallel the existing NPS 20 transmission pipeline and serve an identical transmission function;[19]

    e) not allow customers to select whether to use the NPS 36 Project pipeline leg or existing NPS 20 pipeline leg;[20]

    f) not be built for any specific customer;[21]

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[14] Enbridge AIC at para. 72.
[15] Transcript V2, P8, L8-14
[16] Transcript V1, P135, L2-7; Transcript V1, P156-157, L22-7
[17] Transcript V1, P135, L8-15; Exhibit I.STAFF.25(c)
[18] Transcript V1, P135-136, L26-20 ; Transcript V1, P155, L4-14
[19] Transcript V1, P133-134, L25-10
[20] Transcript V1, P134, L12-15
[21] Transcript V1, P137, L2-19; Exhibit I.APPRO.12

g) not have any directly connected customers;[22]

h) benefit existing customers; and[23]

i) carry natural gas on behalf of other shippers.[24]

30. In this context, APPrO submits that it is important for the OEB to distinguish between Enbridge's actual evidence of project need, as described above, versus what APPrO believes is a fundamental mischaracterization of Enbridge's Expression of Interest ("**EOI**") processes. Specifically:

a) the EOI was **non-binding** (Enbridge explains in evidence the non-binding nature in respect of its 2021[25] and 2023 EOIs[26], and Enbridge reiterates this point in submissions);[27]

b) the Project is not designed to serve a specific customer or group of customers, rather incremental capacity created by the project will be made available to new customers on a first come, first served basis;[28]

c) there are a number of other unidentified customers that are likely to benefit from this project;[29] and

d) the actual group of customers that actually utilize the capacity of the Project may differ significantly from the non-binding EOI results - for example, the Stellantis battery plant did not bid into the 2021 EOI, rather they showed up after the 2021 EOI and were allocated capacity by Enbridge on a first-come, first-serve basis.[30]

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[22] Tab 1, Schedule 1, Attachment 8, Page 1 of 7; Transcript V1, P114, L11-13
[23] Exhibit I.APPRO.12; Exhibit.I.STAFF.25
[24] Transcript V1, P114, L18-22
[25] Exhibit B, Tab 1, Schedule 1 at para. 13.
[26] Exhibit B, Tab 1, Schedule 1 at para. 23.
[27] Enbridge Argument-in-Chief at para. 10.
[28] Transcript Vol. 1 at page 135, lines 2-20.
[29] Transcript Vol. 1 at page 135, line 26 to page 136, line 20.
[30] Transcript Vol. 1 at page 155, lines 4-14.

31. The use of the E.B.O. 134 economic test is in accordance with the OEB's E.B.O. 134 Report of the Board,[31] the Filing Guidelines on the Economic Tests for Transmission Pipeline Applications (EB-2012-0092),[32] the OEB's E.B.O. 188 Final Report of the Board,[33] and the Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario.[34]

32. A complete review of each of these reports leads to the conclusion that the E.B.O. 134 economic test ("**E.B.O. 134**") correctly applies to transmission pipeline leave to construct applications, and the E.B.O. 188 economic test ("**E.B.O. 188**") is the appropriate test for distribution system expansion projects.

33. Certain other ratepayer groups (whose members have benefited since 1987 from decades of transmission system expansions reinforcements pursuant to the existing E.B.O. 134 Report of the Board) are likely to argue that Enbridge should impose CIACs for the Project.

34. Specifically, by letter dated December 8, 2022, counsel for the Industrial Gas Users Association ("**IGUA**"), subsequently supported by the Federation of Rental-housing Providers of Ontario ("**FRPO**") and Environmental Defence ("**ED**"), argued that CIACs should be required from new customers.

35. In this context, the OEB in Procedural Order No. 4 issued December 14, 2022 stated that the economics of the Project, the applicability of EBO 134 and EBO 188, and the extent to which CIAC should be required are all issues that are within scope of the Application.[35]

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[31] The OEB's E.B.O. 134 Report of the Board, June 1, 1987, online: <https://www.oeb.ca/sites/default/files/EBO134-Board-Report-review-of-natural-gas-system-19870601.pdf>.

[32] The OEB's Filing Guidelines on the Economic Tests for Transmission Pipeline Applications (EB-2012-0092), February 21, 2013, online: <https://www.oeb.ca/oeb/_Documents/Regulatory/Filing_Guidelines_Tx_Pipelines_Applications.pdf>.

[33] The OEB's E.B.O. 188 Final Report of the Board, January 30, 1998, online: <https://www.oeb.ca/documents/cases/Xo188/decision.pdf>.

[34] The OEB's Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, online: <https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2019-01/EBO-188-AppB-Guidelines-Gas-Expansion-19980130.pdf>.

[35] The OEB's Procedural Order No. 4, December 14, 2022, P3, online: <https://www.rds.oeb.ca/CMWebDrawer/Record/765156/File/document>.

A. <u>Changing the E.B.O. 134 economic test is not the appropriate solution to solve a cost allocation problem</u>

36. This is not the appropriate forum to deal with changes to E.B.O. 134 policy. While APPrO acknowledges the OEB is not bound by previous decisions, they have a high degree of persuasive value.[36]

37. If the OEB believes it should revisit the E.B.O. 134 economic test, including whether CIACs should be collected, it should only do so as part of a generic hearing and not on an ad hoc basis as part of this Application. The OEB has addressed other broader issues – such as the Export Transmission Service (ETS) tariff – in distinct proceedings.

38. Changes to E.B.O. 134 and existing CIAC policy were never within the scope of this proceeding. This is not a routine matter. The issues list used by the OEB in this proceeding is the same one used for all typical hydrocarbon pipeline leave to construct applications.[37] Procedural Orders issued by the OEB have merely repeated Issue 3.3 in the standard issues list about the "applicability of EBO 134 and EBO 188" to the Project. The issues list did not change because of IGUA's letter on December 8, 2022, nor was a change to the standard issues list requested.[38] Procedural Order 4 issued on December 14, 2022 only gave Enbridge an opportunity to provide additional evidence on applicability of EBO 134 and EBO 188 as part of its proposed update to its application.

39. The Ministry of Energy also recognizes that coordination is required between the fuels and electricity sectors for energy transition.[39] Proper notification has not been given to potentially affected parties (e.g., other electric and gas utilities) and the record in this proceeding does not reflect the breadth of consultation and expert evidence that would be required.

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[36] OEB Decision RP-2003-0203, s.5.3.3 online: <https://www.rds.oeb.ca/CMWebDrawer/Record/42782/File/document>
[37] Procedural Order No. 1.
[38] IGUA, Request for Abeyance, December 8, 2022, online: <https://www.rds.oeb.ca/CMWebDrawer/Record/763954/File/document>
[39] Ontario Government, Electrification and Energy Transition Panel, accessed on September 12, 2023, online: <https://news.ontario.ca/en/release/1002487/ontario-finalizes-electrification-and-energy-transition-panel>

40. As explained by Mr. MacPherson "[t]here are a number of unidentified customers" that will benefit from the Project including the NextStar battery plant.[40] Invest Windsor Essex identifies several other customers that will benefit from the Project, including Stellantis, Amazon, and 4 other battery plant supply chain companies.[41] None of these other customers are represented in this proceeding.

41. Indeed, the OEB prepared a discussion paper in advance of commencing E.B.O. 134 outlining criteria previously used by the OEB when assessing the public interest in system expansion projects and examined economic feasibility tests currently used by the gas distributors' when evaluating system expansion projects. Five alternative tests were presented: the Comparative Cost Test, the Aggregate Customer Net Benefit Test and Union Gas presented three tests of its own.[42] This same level of rigor is not present in the current proceeding.

42. In addition, any changes to E.B.O. 134 would need to be phased-in over time to ensure those changes can be properly incorporated into business forecasts and decisions.

43. For example, two days ago - December 12, 2023 - was the proposal submission deadline under the IESO's LT1 RFP[43] process procuring, *inter alia*, new natural gas-fired capacity that would, if successful, be contractually obliged to reach commercial operation before a milestone date of May 1, 2028, and in any event before a longstop date of November 1, 2029.[44] Generators bidding into the IESO's LT1 RFP were required to forecast all of their fixed capital costs (including any CIACs) as part of this RFP process, and they will be contractually held to those forecasts to build their facilities. Those decisions have been made. They would have very likely viewed the near four-decade long track record of transmission expansion, concluded that no CIAC would be required and, subsequently, not included such costs in their bid.

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[40] Transcript Vol. 1 at page 135, line 21 to page 136, line 20.
[41] Windsor Essex Letter of Support dated November 9, 2023 (available online at: https://www.rds.oeb.ca/CMWebDrawer/Record/822392/File/document)
[42] E.B.O. 134 at paras 3.6 and 6.25.
[43] https://www.ieso.ca/-/media/Files/IESO/Document-Library/long-term-rfp/LT1-RFP-Final-20230929.ashx
[44] https://www.ieso.ca/-/media/Files/IESO/Document-Library/long-term-rfp/LT1-Contract-20230929.ashx

44. Consequently, any changes made to the E.B.O. 134 economic test should not come into force until 2030 (i.e. after the LT1 facilities are built). This will ensure that all customers, including natural gas fired generators, are given the time needed to properly account for such changes in cost forecasts and business decisions.

45. This is what regulatory certainty and predictability entails in practice.

B. A CIAC is not justified under E.B.O. 134

46. APPrO agrees with Enbridge that, subject to narrow exceptions, the E.B.O. 134 economic test does not contemplate payment of a CIAC. APPrO agrees that none of the E.B.O. 134 exceptions apply.[45] Imposition of a CIAC on the Project would very likely have a direct adverse and material impact on capital investment and job creation throughout the province.[46] In any event, a CIAC cannot be calculated for the Project.[47]

47. The imposition of a CIAC in these circumstances is not permitted under E.B.O. 134.

48. The Project does not meet either of the conditions precedent required of an expansion CIAC:[48] (a) where the sole purpose is to supply gas into a new area; **and** (b) where the evaluation process demonstrates an undue burden on existing customers.[49] The purpose of the Project is to provide more transmission capacity to serve a broad geographic area where a number of customers will benefit and there is no evidence that the Project will place an undue burden on existing customers.

49. The fact that Project demand is occurring in both the Leamington and Windsor areas, which are over 45 km apart, and across several industries demonstrates that the Project facilitates the transmission of natural gas over a broad area to supply an array of customers and businesses.

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[45] Transcript V1, P115, L4-19.
[46] Exhibit I.APPRO.9; Transcript V1, P116-118, L7-13.
[47] Transcript V1, P116, L7-19.
[48] Decision and Order EB-2019-0183, Applications for approval of Owen Sound Reinforcement Project Leave to Construct & Rate M17, at page 20.
[49] E.B.O. 134 at para 7.29.

50. Even if subsidization is required for the Project from existing customers, which is not admitted but expressly denied, subsidization is expressly permitted under E.B.O. 134. The OEB acknowledged that the discounted cash flow methodology may result in approval of a project which requires a subsidy from existing customers in its early years, with the subsidy being offset by the benefits in later years.[50] Thus, short-term subsidization by existing customers, if present, is acceptable in the three-stage test and those receiving the subsidy now will likely subsidize future customers somewhere else down the line.

51. Finally, APPrO rejects any interpretation that E.B.O. 134 was primarily convened to address the issue of expansion of gas utility services into smaller, uneconomic communities after the federal Distribution System Expansion Program and Canada Oil Substitution Program were discontinued in the 1980s. Paragraph 7.32 of E.B.O. 134 clearly contemplates that government support, such as the recent *Expansion of Natural Gas Distribution Systems,* is <u>in addition</u> to the E.B.O. 134 economic test.[51] In APPrO's view, this represents an overly narrow interpretation of E.B.O. 134 and does not accord with subsequent decisions of the OEB (discussed below).[52]

52. The OEB clearly articulated in E.B.O. 134 that it was a special hearing to evaluate economic feasibility tests used in the public interest determination for transmission leave to construct applications.[53] The intention was to canvass a broad spectrum of participants to critically re-evaluate the economic tests based on a broad list of criteria, one of which included "economic feasibility", related to the public interest.[54]

C. <u>OEB has decided that Panhandle cost allocation issues are to be determined as part of Enbridge's rebasing application</u>

53. Allocation of Panhandle system costs has been at issue since 2016. It appears that parties in this proceeding wish to revisit the issue of cost allocation indirectly through the imposition of a CIAC. However, prior decision of the OEB clearly direct that Panhandle cost allocation be determined as part of Enbridge's 2024 cost of service rate application. APPrO submits

[50] E.B.O. 134 at para 7.26.
[51] *Expansion of Natural Gas Distribution Systems*, O Reg 24/19.
[52] See also E.B.O. 134 at para 7.32.
[53] E.B.O. 134 at paras 2.14, 3.6, 5.2 and 6.1.
[54] E.B.O. 134 at paras 3.6, 3.7 and 5.3.

that cost allocation issues of the Panhandle system are within the scope of OEB proceeding EB-2022-0200, not this leave to construct application for the Project.

54. In EB-2016-0186, Union Gas proposed a cost allocation methodology for the project that was different from the OEB's approved cost allocation methodology. Union sought to address the addition of significant project costs related only to the Panhandle System (resulting from the reinforcement) and no change to the cost of the St. Clair System. Union was of the view that the combining the Panhandle and St. Clair systems no longer reflected the costs to serve the customers using each respective transmission system. However, the OEB decided in this leave to construct decision that Union Gas's proposed change to the cost allocation methodology should be reviewed at Union Gas's next cost of service application which at that time was expected to be for 2019 rates.[55]

55. In EB-2017-0087, the issue of cost allocation was raised in Union Gas's 2018 rates proceeding.[56] However, Union Gas and Enbridge filed a separate application to amalgamate (the MAADs proceeding) and sought approval of a rate setting mechanism and associated parameters, to be effective January 1, 2019.[57]

56. In EB-2017-0306/0307, the OEB approved the amalgamation of Union Gas and Enbridge and directed Enbridge to file a cost allocation study for the legacy Union Gas rate zones in the 2020 rates proceeding.

57. In EB-2019-0194, Enbridge requested that implementation of the cost allocation study be done at the next rebasing. APPrO and IGUA argued that if the implementation of the cost allocation study were delayed until 2024, the existing inequity would continue for another four years and large customers would continue to overpay and urged the OEB panel to implement the changes in 2021. Despite this, the OEB decided to wait until rebasing to make cost allocation changes on a holistic basis than to make selective updates in the interim.[58]

[55] EB-2016-0186
[56] EB-2017-0087
[57] EB-2017-0306/0307
[58] EB-2019-0194, pg. 17.

58. In EB-2020-0156, IGUA filed a motion to review and vary the OEB's decision in EB-2019-0194. However, the OEB dismissed IGUA's motion.[59]

V. THE PANHANDLE REINFORCEMENT PROJECT

59. APPrO represents more than 100 companies involved in the generation of electricity in Ontario.

60. The evidence in this proceeding shows that several APPrO members will benefit from the Project.[60] Numerous other APPrO members will not benefit from the Project, although they will be required to pay for it.

61. Because of the diversity of interests it represents, APPrO has taken both a cautious and prudent approach to assessing project need, alternatives, costs and economics and other impacts.

62. And after a careful reading of the evidence, APPrO is satisfied that Enbridge has met its burden of proof to demonstrate that the Project is in the public interest, and that the relief requested in the Application should be granted.

63. APPrO has reviewed the Argument-in-Chief filed by Enbridge on November 30, 2023 (the "**Enbridge AIC**"). APPrO is supportive of the Enbridge AIC and has structured its submissions to expand on key points that are particularly relevant to its members.

64. For the reasons set out in the Enbridge AIC, and the reasons highlighted below, APPrO agrees with Enbridge that the Project is in the public interest and that the relief requested in the Application should be granted.

A. Issue 1.0: Need for the Project

65. APPrO submits that the Enbridge evidence as well as support from numerous local municipalities and businesses demonstrates the Project is clearly needed. Enbridge received

[59] EB-2020-0156
[60] As discussed above, both the Brighton Beach GS and the East Windsor GS will benefit from the Project.

strong interest from potential customers in early 2023 as part of its second non-binding Expression of Interest and concurrent binding Reverse Open Season.[61]

66. Enbridge has executed four firm transportation contracts for expansion capacity, with contract rate customers, three of which are with existing customers who are expanding their greenhouse operations.[62] The fourth such contract is with Atura, who has executed a five-year Gas Storage and Distribution T2 Contract for firm expansion capacity.[63]

67. Enbridge's updated forecast shows that the existing Panhandle pipeline system cannot accommodate forecasted customer demands beyond November 1, 2024.[64] From a technical standpoint, the existing Panhandle System cannot maintain the required contracted minimum delivery pressure of 1,724 kPag to Brighton Beach GS or 2,275 kPag to Leamington North Gate station.[65] The capacity created by the Project serves customer demand growth across the entire Panhandle System.

68. Specifically, the evidence shows that there will be an approximately 66 TJ/d deficit starting in Winter 2025 and this is forecasted to continue to grow into the future.[66] This demand growth is primarily driven by the greenhouse, power generation, and automotive sectors in the region.[67] The NPS 20 Panhandle Line between Dover Transmission and Comber Transmission Station is currently the largest bottleneck on the Panhandle System.[68] The Project will target this bottleneck by "looping"[69] the pipeline to relieve this transmission system constraint.

69. Importantly for APPrO members, the Project is essential to meet forecasted electricity demand. The IESO has forecasted a capacity need that emerges in 2025 and grows through

[61] Exhibit B Tab 1 Schedule 1 Page 6 of 22
[62] Exhibit J2.12
[63] Exhibit I.PP.32, Attachment 1
[64] EB-2022-0157 Exhibit A Tab 4 Schedule 1 Page 7 of 7
[65] Exhibit B, Tab 2, Schedule 1, pg 15.
[66] Exhibit B, Tab 2, Schedule 1, Figure 3.
[67] Exhibit B Tab 1 Schedule 1 Page 22 of 22
[68] Exhibit B, Tab 2, Schedule 1, pg 13.
[69] I.e., two or more pipelines running in parallel to each other, normally in the same right of way.

the latter part of the decade as a result of nuclear refurbishments and expiring contracts.[70] The need is both local to the Windsor-Essex region, as well as across the province.

70. The Windsor-Essex region is experiencing rapid growth in electricity demand from greenhouses as well as investments in the lithium-ion battery and automotive sectors. Peak electricity demand in the Windsor-Essex and Chatham areas is forecast to grow from roughly 500 megawatts in 2022 to about 2,100 megawatts in 2035, equivalent to adding cities the size of Ottawa and London to the grid.[71]

71. To address this and other system-wide needs for new capacity, the IESO recently completed the Expedited Long-Term RFP (E-LT1-RFP) procurement that is explicitly intended to add new capacity to the grid by the middle of this decade – with one of the areas highlighted by the IESO for capacity was the Windsor-Essex region. The IESO ultimately procured 100 MW of new capacity from the East Windsor GS that will be in operation by the end of 2026 to help meet local and provincial resource adequacy needs.[72]

72. The IESO’s 2021 and 2022 Annual Acquisition Reports have identified that while the transmission infrastructure projects are being developed there is a need for re-contracting Brighton Beach GS as it is uniquely positioned to meet reliability needs in the Windsor-Essex region. This includes ensuring the region has the power it needs during demand peaks and supporting the integration of intermittent renewable generation already in place.[73]

73. The Ontario Government states that eliminating natural gas-fired generation in the near term from Ontario’s electricity system would not only result in rotating blackouts but would also hamper efforts to electrify and reduce emissions in the province by making electrification significantly more costly.[74] The Project is needed to meet electricity demand in the same geographic area as the Panhandle system.

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[70] Exhibit I.APPRO.10
[71] Exhibit I.APPRO.10
[72] IESO, Expedited Long-Term RFP (E-LT1 RFP) – Final Results, September 18, 2023 online: <https://www.ieso.ca/-/media/Files/IESO/Document-Library/long-term-rfp/ELT1-RFP-Selected-Proponents.ashx>
[73] Exhibit I.APPRO.10
[74] Exhibit I.APPRO.10

B. Issue 2.0: Project Alternatives

74. APPrO agrees with Enbridge that the Project is the best alternative to satisfy the project need. The table below summarizes APPrO's understanding of the options considered by Enbridge and brief reasons for rejection of those options.[75]

[75] Exhibit I.STAFF.7, Attachment 1, updated 2023-10-03

	Alternative Project	Reasons For Rejection	Details	Cost Per Unit of Capacity
	Loop Existing NPS 20 Panhandle Line west of Dover Transmission	N/A	This is the proposed Project.	$2.13 million per TJ
			Facility Alternatives	
1	Upsize and replace either the NPS 16 or NPS 20 Panhandle lines west of Dover Transmission	1) Not technically feasible 2) Increased environmental and landowner impacts	1) NPS 16 cannot serve system demands on its own while NPS 20 is out of service during replacement. NPS 16 and NPS 20 too far apart (9 km) to temporarily connect users on NPS 16. 2) Replacement of NPS 16 does not address bottleneck on NPS 20. New greenfield pipeline easements required.[76]	
2	New LNG Storage Facility	1) Not financially viable	1) Estimated $580 million to address 156 TJ/d of system shortfall.[77]	
			Integrated Resource Planning Alternatives	
3	Firm exchange between Dawn and Ojibway	1) Not commercially available 2) Not technically feasible 3) Ojibway not a liquid trading point	1) There are no commercial services available to be contracted at Ojibway with third parties that can fully eliminate the forecasted 5-year Panhandle System shortfall.[78] 2) While Ojibway can serve demands near Windsor, not efficient for serving demands on remainder of Panhandle.[79] OEB agreed in EB-2016-0186 (pg 26). 3) Ojibway is a trans-shipment point between two pipeline systems. There is no natural gas market price or transaction reporting coverage to provide price transparency at Ojibway and therefore price protection for Panhandle customers.[80]	$3.15 million per TJ
4	Firm exchange between Dawn and Ojibway (21 TJ/d) in combination with looping of the NPS 20 Panhandle Line west of Dover	1) Impractical operations, unreasonable landowner impacts	1) Only shortens pipeline loop from 18.93 km to 17.86 km to provide same capacity as Project. End point now in middle of farmer's field –	$2.48 million per TJ

[76] Exhibit C Tab 1 Schedule 1 Page 6 of 22
[77] Exhibit C Tab 1 Schedule 1 Page 10 of 22
[78] Exhibit C Tab 1 Schedule 1 Page 11 of 22: see the list of technical reasons at paragraph 37.
[79] Exhibit C Tab 1 Schedule 1 Page 11 of 22
[80] Exhibit C Tab 1 Schedule 1 Page 13 of 22; Exhibit B Tab 3 Schedule 1 Page 9 of 10

	Alternative Project	Reasons For Rejection	Details	Cost Per Unit of Capacity
	Transmission (147 TJ/d) (Hybrid Alternative 1) *Project terminates at farmer's field*	2) Worse economics than Project 3) Financial and contract renewal risk	difficult to access for maintenance and connection to utility services.[81] 2) Reduction in the length of the loop by 1.07 km would decrease the proposed Project cost by $7 million. Whereas firm exchange would cost $4.2 million annually, resulting in $66.2 million cost over term. 3) Future price and renewal risk with respect to exchange services.[82]	
5	Firm exchange between Dawn and Ojibway (21 TJ/d) in combination with looping of the NPS 20 Panhandle Line west of Dover Transmission (132 TJ/d) (Hybrid Alternative 2) *Loop terminates at Wheatley Road*	1) Does not meet forecasted demand. 2) Worse economics than Project 3) Financial and contract renewal risk	1) Provides 15 TJ/d less capacity compared to the proposed Project, does not provide enough capacity to serve the 5-year forecast growth.[83] 2) Reduction in length of the loop by 2.73 km would decrease the proposed Project cost by $27.5 million. Whereas firm exchange would cost $4.2 million annually, resulting in $66.2 million cost over term.[84] 3) Future price and renewal risk with respect to exchange services.[85]	$2.59 million per TJ
6	Trucked CNG	1) Not technically feasible	1) Approximately 420 truck loads per day would be required to meet the shortfall capacity of 156 TJ/d. Not practical in terms of logistics and security of supply.[86]	
7	Enhanced Targeted Energy Efficiency (ETEE)	1) Not technically feasible 2) Not economically feasible	1) Posterity Group report indicates that ETEE reductions would not offset demand and interim solution would be required before full ETEE implementation occurs in Winter 2029/2030.[87]	$8.2 million per TJ

[81] Exhibit C Tab 1 Schedule 1 Page 16 of 22
[82] Exhibit C Tab 1 Schedule 1 Page 18 of 22
[83] Exhibit C Tab 1 Schedule 1 Page 17 of 22
[84] Exhibit C Tab 1 Schedule 1 Page 17 of 22
[85] Exhibit C Tab 1 Schedule 1 Page 18 of 22
[86] Exhibit C Tab 1 Schedule 1 Page 19 of 22
[87] Exhibit C Tab 1 Schedule 1 Page 20 of 22

75. FRPO requested Enbridge to consider the scenario where 58 TJ/d of capacity is available at Ojibway. APPrO is very concerned that this is not a realistic scenario that should be considered by the OEB. Enbridge has been clear that the incremental 37 TJ/d of Ojibway capacity is not available to be contracted by Enbridge and facility modifications are required to accommodate such a request. FRPO had every opportunity to file their own evidence in this proceeding and chose not to do so. Finally, none of the options proposed by FRPO are cheaper than the Project on a cost per unit of capacity basis.[88]

76. APPrO also received confirmation that there are no additional alternatives identified by Enbridge to accommodate the 5-year system shortfall. The existing NPS 20 pipeline is operating at its maximum operating pressure and cannot be further increased.[89]

C. Issue 3.0: Project Costs and Economics

77. APPrO agrees with Enbridge that the Project costs are reasonable and E.B.O. 134 is the appropriate economic test to apply to the Project.[90] APPrO agrees that the result of the E.B.O. 134 analysis is that the Project has a net present value of $226 million to $353 million at stage 2 and a net present value of $333 million to $460 million at stage 3.[91] Thus, the Project passes the E.B.O. 134 economic test at either stage 2 or stage 3 and, therefore, the Project is in the public interest.

78. This net present value is underestimated and only includes quantifiable benefits.[92] For example, none of the electricity system benefits have been included within the stage 3 analysis.[93] A firm and reliable source of gas-fired generation requires a firm and reliable supply of natural gas.[94] Electricity reliability is vital to economic prosperity in the Panhandle region and gas generation resources, such as Brighton Beach GS, will be required beyond 2030 to meet electricity demand.[95]

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[88] FRPO Additional Request, November 30, 2023.
[89] Exhibit I.APPrO.3
[90] Enbridge AIC at paras. 70 and 72; Transcript V1, P114, L23-27
[91] Enbridge AIC at para. 74
[92] Transcript V1, P121, L4-5.
[93] Transcript V1, P128, L11-17; Exhibit I.APPRO.10(b).
[94] Transcript V1, P127, L20-25.
[95] Transcript V1, P128, L1-5; Exhibit I.APPrO.8

79. The Project addresses both natural gas and electricity constraints in the Panhandle region.[96] The outcome of this proceeding has consequences for the gas and electricity sectors.

80. APPrO submits that the stage 3 benefits are much higher once electricity benefits are accounted for. The following adverse consequences, which have not been incorporated into the stage 3 analysis, may result if the Project is not approved:

   a) Replacing the generation capacity that the IESO has been directed by the Minister of Energy to procure will be significantly more expensive to meet the demand and reliability needs of the Panhandle region;[97]

   b) An increase in electricity rates is likely required for the IESO to procure the necessary generation or transmission capacity to replace the proposed gas-fired generation;[98]

   c) There is currently no technology that can replace the characteristics of gas-fired generation on a like-for-like basis to maintain system reliability until nuclear refurbishments are complete and new non-emitting technologies such as storage mature, meaning that no technology can be turned on and ramped up quickly to ensure the province does not need to be reliant on emergency actions such as conservation appeals and rotating blackouts to stabilize the grid;[99]

   d) While during most hours throughout the year Ontario can meet its electricity generation needs with nuclear, hydroelectric, bioenergy, wind and solar power, natural gas generation also acts as the province's insurance policy that can be turned on if the wind is not blowing or sun is not shining, or another generator is offline for repairs;[100] and

[96] Exhibit I.APPRO.10.
[97] Exhibit I.APPRO.10.
[98] Exhibit I.APPRO.10.
[99] Exhibit I.APPRO.10.
[100] Exhibit I.APPRO.10.

e) Access to energy is critical for economic growth in Ontario and businesses could relocate to other jurisdictions if energy is not available (for example greenhouses will move to jurisdictions such as Michigan, Ohio and North Carolina).[101]

81. APPrO agrees with Enbridge that the Project benefits many other parties within the Panhandle region, not just the contract customers who responded to the expression of interest.[102] The Project will directly support job growth, increase property tax revenue for the affected municipalities and increase tax revenue for the province.[103] Gross domestic product contributions to Ontario's economy from farmgate sales of greenhouses alone in the Panhandle region are projected to exceed $2 billion per year by the end of the decade.[104]

82. Indeed, the Project has strong support from regional municipalities as well as major customer groups.[105] APPrO submits that regional economic growth and prosperity is dependent on this Project. A predictable regulatory framework and reliable access to energy is fundamental for attracting future business to Ontario.

D. <u>Other issues</u>

83. APPrO supports the submissions of Enbridge on all other remaining issues in the proceeding, including environmental matters, land matters and indigenous consultation.[106]

84. APPrO also supports Enbridge's request for conditions of approval identical to those in the Standard Conditions of Approval appended to the standard issues list for a typical hydrocarbon pipeline leave to construct application under section 90 or 91 of the *Ontario Energy Board Act*.[107]

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[101] Exhibit I.APPRO.9; OGVG, Written Evidence of Dr. Petro, at page 4.
[102] Exhibit I.STAFF.25(c); Exhibit I.APPRO.10(a).
[103] Exhibit I.APPRO.10
[104] Written Evidence of Dr. Petro, at page 1.
[105] Exhibit B, Tab 1, Schedule 1, Attachments 3 – 7
[106] Enbridge AIC at pgs 34-41.
[107] Exhibit I Tab 1 Schedule 1 Page 1 of 1

VI. CLOSING

85. APPrO agrees with Enbridge that the Project is in the public interest and that the relief requested in the Application should be granted for the following reasons:[108]

a) The OEB's current Letter of Direction emphasizes that regulatory certainty is imperative to continued economic investment in the province;

b) The Project is clearly a transmission project on the facts and E.B.O. 134 applies;

c) A CIAC is not appropriate for the Project;

d) The Project is needed to meet both gas and electricity demand in the Panhandle region;

e) The Project is the best alternative to meet the identified need; and

f) The Project meets the E.B.O. 134 economic test at both stage 2 and stage 3 and is in the public interest.

86. As one of the only intervenors in this proceeding that can credibly claim to represent the interests of both Incumbent Consumers and Incremental Consumers, APPrO submits the OEB should deny the request to modify or discard entirely the existing E.B.O. 134 framework for this Project. This is not the appropriate forum to revise E.B.O. 134, a CIAC is not justified and the OEB has already determined that issues of cost allocation are to be decided as part of Enbridge's cost of service application.

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[108] Enbridge AIC at paras 2-3.

ALL OF WHICH IS RESPECTFULLY SUBMITTED THIS 14 TH DAY OF DECEMBER, 2023

BORDEN LADNER GERVAIS LLP

Per:

J Vellone

John Vellone

Counsel to the Association of Power Producers of Ontario