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Enbridge Gas Inc.
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VIA EMAIL and RESS

November 30, 2023

Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Nancy Marconi:

Re: Enbridge Gas Inc. ("Enbridge Gas" or the "Company")
Ontario Energy Board ("OEB") File No. EB-2022-0157
Panhandle Regional Expansion Project ("Project")
Argument-in-Chief

In accordance with the OEB's Procedural Order No. 8, enclosed please find the Argument-in-Chief submission of Enbridge Gas in the above noted proceeding.

If you have any questions, please contact the undersigned.

Sincerely,

[Original Signed By]

Haris Ginis
Technical Manager, Leave to Construct Applications

c.c. Charles Keizer (Torys)
Tania Persad (Enbridge Gas Counsel)
Zora Crnojacki (OEB Staff)
Intervenors (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 use agreements.

ENBRIDGE GAS INC.

ARGUMENT-IN-CHIEF

EB-2022-0157

November 30, 2023

Table of Contents

A. Introduction

1. This is the Argument-in-Chief ("AIC") of Enbridge Gas Inc. ("Enbridge Gas" or the "Company") in its leave-to-construct application in respect of the Panhandle Regional Expansion Project (the "Project"). The Project includes the construction of (a) approximately 19 km of Nominal Pipe Size ("NPS") 36 natural gas pipeline from the existing Enbridge Gas Dover Transmission Station in the Municipality of Chatham-Kent to a new valve site in the Municipality of Lakeshore; and (b) ancillary measurement, pressure regulation and station facilities within the Township of Dawn Euphemia and in the Municipality of Chatham-Kent.

2. Enbridge Gas requests the following orders from the OEB:

    a. Pursuant to Section 90(1) of the *Ontario Energy Board Act*, 1998 (the "Act"), an Order granting leave to construct the Project; and

    b. Pursuant to Section 97 of the Act, an Order or Orders approving the proposed form of Pipeline Easement Agreement and the proposed form of Temporary Land Use Agreement.[1]

3. Enbridge Gas submits that the Project is in the public interest and that the requested relief should therefore be granted. Without the Project, based upon Enbridge Gas's current Design Day demand forecast, the Panhandle Transmission System[2] ("Panhandle System") demand will exceed capacity by 66 TJ/d beginning in Winter 2024/2025, which increases to 156 TJ/d by Winter 2028/2029. As a result of this demand growth, there is a need for capacity to meet the forecasted firm customer demands by November 1, 2024 and beyond. The Project:

[1] See Exhibit G-1-1, Attachments 3 and 4, respectively.

[2] The Panhandle System transports natural gas between Enbridge Gas's Dawn Compressor Station, located in the Township of Dawn Euphemia, and the Ojibway Valve Site, located in the City of Windsor.

- is necessary to expand Enbridge Gas's Panhandle System to reliably serve the increased demands for firm service in the Panhandle Market[3] (in particular, the Leamington-Kingsville and Windsor areas);
- is the best alternative relative to both facility and non-facility alternatives, and targets the largest pressure bottleneck on the Panhandle System to provide additional capacity of 168 TJ/d;
- is economic at an estimated cost of $358 million and based on an economic assessment consistent with the OEB's E.B.O. 134 Report; and,
- is based on a prudent and pragmatic approach to satisfy the first five years of the forecasted 10-year period increasing demand.[4]

4. The balance of this AIC discusses the need, alternatives, costs and economics, engineering and construction, environmental and land-related matters, as well as Indigenous consultation relating to the Project.

B. Project Need

5. As noted, the Project is necessary to expand Enbridge Gas's Panhandle System to reliably serve all customers connected to the Panhandle System and the increased demands for firm service in the Panhandle Market. If the Project is not undertaken, contract rate customers that rely on access to natural gas will not expand in Ontario and may move their operations to other jurisdictions, outside of Ontario, where their natural gas needs can be served.[5] As stated in Mr. Macpherson's Testimony:

> What we had heard from, ultimately, from our customers [is] they need this pipeline to expand their business, so this [failure to grant the leave to construct] would lead to […] growth occurring in other jurisdictions.[6]

Similarly, Dr. Petro testified on behalf of the Ontario Greenhouse Vegetable Growers to the effect that it would not be viable to operate a large-scale greenhouse

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[3] The Panhandle Market is the area served by the Panhandle System that serves residential, commercial, and industrial markets through natural gas distribution systems in the municipalities of Dawn-Euphemia, St Clair, Chatham-Kent, Windsor, Lakeshore, Leamington, Kingsville, Essex, Amherstburg, LaSalle, and Tecumseh.

[4] Exhibit B-1-1, p 5; Exhibit C-1-1, p.3.

[5] See Exhibit B-1-1, p.17.

[6] EB-2022-0157, Transcript, Vol 2 (November 14, 2023), p. 191.

operation in the Panhandle region in the absence of sufficient natural gas capacity and without sufficient natural gas capacity “future expansion […] would go to jurisdictions where it makes economic sense”.[7]

6. As a consequence, without the Project, Ontario would not receive the total direct capital investment in excess of $4.5 billion that the Contract Rate customers have identified in respect of their business operations in Southern Ontario, or the resulting 6,900 jobs also identified.[8]

7. The current (Winter 2022/2023) Panhandle System capacity is 737 TJ/d. The forecast firm demand on the Panhandle System for Winter 2022/2023 is 698 TJ/d. Enbridge Gas’s current Design Day demand forecast indicates that the Panhandle System demand will increase by 32 TJ/d to 730 TJ/d by Winter 2023/2024, and by an additional 72 TJ/d to 802 TJ/d in Winter 2024/2025. As a result of this growth, there is a need for capacity to meet the forecasted firm customer demands by November 1, 2024, and beyond.[9]

8. Enbridge Gas is requesting minimum five-year contracts from interested contract rate customers for capacity on the Panhandle System starting in November 2024. Contract rate customer demand makes up approximately 94% of the capacity of the proposed Project.

9. Enbridge Gas forecasts that general service customer demand in the Panhandle Market will increase by approximately 4.6% between Winter 2022/2023 and Winter 2030/2031. Incremental demands from general service customers make up approximately 6% of the incremental capacity of the proposed Project. The general service growth forecast is informed by Enbridge Gas’s internal customer attachment forecast.[10]

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[7] EB-2022-0157, Transcript, Vol 3 (November 15, 2023), pp. 168-169.
[8] Exhibit B-1-1, p. 15 and Exhibit E-1-1, p. 6.
[9] Exhibit B-2-1, p. 11.
[10] Ibid, pp. 10-11.

2023 Expression of Interest and Reverse Open Season

10. On February 23, 2023, Enbridge Gas launched a non-binding Expression of Interest (the "2023 EOI") and concurrent Reverse Open Season ("ROS") for the Panhandle Market. The purpose of the 2023 EOI was to re-confirm customer interest in incremental capacity on the Panhandle System following the Project's leave to construct application being placed into abeyance in December 2022. Customers who responded to the 2023 EOI were also requested to provide additional information regarding the viability of interruptible service as an alternative to new firm service, including whether they would be more inclined to consider interruptible service over new firm service if the ability to negotiate lower than posted interruptible rates was available. Customers were also asked to confirm that their 2023 EOI bid amounts were inclusive of all future expected natural gas conservation activities, including natural gas conservation activities within and outside of Enbridge Gas's Demand Side Management programs, and the use of non-natural gas alternative options.

11. The ROS provided existing contract customers another opportunity to formally de-contract existing firm or interruptible capacity. The ROS also provided existing customers the opportunity to request to convert existing firm service to interruptible service.

12. To provide clarity and respond to any questions regarding the 2023 EOI and ROS process, Enbridge Gas account managers directly contacted each contract rate customer in the Panhandle Market. In addition to direct outreach, all existing contract customers were invited to attend an in-person meeting held on March 7, 2023, and/or a virtual meeting held on March 23, 2023. A meeting with local economic development officials was also held on March 2, 2023, to inform them of the process and timelines, and to answer any questions related to the forms.

13. The 2023 EOI and ROS process closed on April 6, 2023, thirty business days following its launch. All bids received were acknowledged via email from Enbridge Gas. A total of 42 2023 EOI bid forms were received from 39 entities, indicating

approximately 197 TJ/d of interest over the 2024-2033 period. The 197 TJ/d is incremental to the capacity that has already been contracted for by customers via a previous Expression of Interest process carried out in 2021 (the "2021 EOI") and through the normal course of business since the close of the 2021 EOI process. Of the 42 2023 EOI bids received, 38 bids were from the greenhouse sector, 2 bids were from the power sector and 2 bids were from the commercial sector. The results of the 2023 EOI are summarized in Table 1 below. There were no requests received from existing contract customers via the ROS to de-contract existing firm or interruptible capacity.

Table 1 – 2023 EOI Bid Summary by Year (m3/hr) [11]

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Total
New/Incremental Firm	52,432	84,503	37,807	25,802	32,952	17,204	13,732	12,547	7,277	2,325	286,581
Interruptible to Firm Conversion	66	8,484	-	-	-	-	-	-	-	-	8,550
Firm Turnback	-	-	-	-	-	-	-	-	-	-	-
Firm to Interruptible Conversion	-	-	-	-	-	-	-	-	-	-	-
Net New/Incremental Firm (by year)	**52,498**	**92,987**	**37,807**	**25,802**	**32,952**	**17,204**	**13,732**	**12,547**	**7,277**	**2,325**	**295,131**
Net New/Incremental Firm (cumulative)	52,498	145,485	183,292	209,094	242,046	259,250	272,982	285,529	292,806	295,131	
TJ/day (by year)	**33**	**71**	**24**	**16**	**21**	**11**	**9**	**8**	**5**	**1**	**197**
TJ/day (cumulative)	33	104	127	143	164	175	183	191	196	197	

Notes:
1) The volumes received through the 2023 Expression of Interest process were in cubic meters of gas per hour (m3/hr).
2) The 2023 Expression of Interest results, combined with the previously contracted volumes from the 2021 Expression of Interest process were used to generate an informed demand forecast.

14. The above 2023 EOI results were received notwithstanding that 2023 EOI respondents were asked to indicate the viability of interruptible service (i) as an alternative to new firm service and (ii) in the event of the ability to negotiate lower than posted interruptible rates, if available. Where responding customers indicated interruptible service was not a viable option, identified reasons included: disruption to operations/productivity impacts; potential for crop loss/production loss; contractual obligations with the IESO/regional power generation; increased cost/availability/emissions associated with alternate fuel sources; installation and maintenance costs of backup fuel systems; and CO_2 requirements for greenhouses. Out of the 42 2023 EOI bids received, only 2 bids (3% of total 2023 EOI interest) indicated that interruptible service was a viable alternative and that they could rely

[11] Exhibit B-1-1, para. 26.

on alternate fuel sources during an interruption event. For those two bids, no interruptible service was requested and there was no ROS request to convert existing firm service to interruptible service. Nevertheless, Enbridge Gas excluded the firm demands from these two bids from the updated demand forecast.

15. There were five bids received (8% of total 2023 EOI interest, inclusive of the two bids referenced in the paragraph above) where customers indicated they would consider interruptible service as an alternative to firm service, with a required reduction in interruptible rates ranging between 20% and 35% below current rates. Although responding affirmatively to the economic proposition, three of the five responding bids indicated that interruptible service was not a viable option and provided no indication of how they would comply during an interruption event. Enbridge Gas chose to exclude the firm demands related to the above bids from the updated demand forecast, which underpins the need for the Project and further underpins the conservative basis for the updated demand forecast.

16. Further supporting the strength of the demand forecast, responding customers who submitted a 2023 EOI form were asked to confirm whether Enbridge Gas had discussed energy conservation program offerings with them,[12] which all customers confirmed. Customers also confirmed that their 2023 EOI bid volumes were inclusive of all future natural gas conservation activities, including natural gas conservation activities within and outside of Enbridge Gas's Demand Side Management programs, and the use of non-natural gas alternative options.

1. Contract Rate Customers Have Unique Natural Gas Needs

17. As noted, the majority of incremental natural gas demand driving the Project has come from the greenhouse and electricity generation sectors. Each sector has its own unique natural gas supply need that cannot be readily accommodated by alternative energy sources.

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[12] In addition to other communications, customers were also reminded of Enbridge Gas's DSM programs during the in-person customer meeting on March 7, 2023, as well as during the March 23, 2023, virtual customer meeting (Exhibit B-1-1, para. 26).

(a) Greenhouse Sector

18. The growth of the controlled-environment greenhouse industry in Southwestern Ontario is both vital to the economic prosperity of the region and Ontario and the industry is particularly reliant on natural gas.

19. The greenhouse market in Southwestern Ontario has experienced significant growth, increasing in size from approximately 1,500 acres in 2007 to over 3,500 acres in 2022. Dr. Petro testified that the acreage of greenhouses around the Leamington-Kingsville area is expected to grow by 4,000 acres within the next 20 years, including by approximately 3,000 acres between now and 2031.[13] This is part of a trend in the region which has experienced an average growth of 5% each year since 2011, and is expected to continue at this pace until at least 2031.[14] This industry provides approximately 14,500 jobs in Southwestern Ontario and supports food processing plants and packagers located in the area. On average, every acre of greenhouse development: i) creates jobs for five employees, ii) results in significant capital investment of approximately $2,000,000 per acre, iii) results in additional spin-off employment, and iv) produces approximately $370,000 worth of produce (farm gate value).[15] On the 2023 EOI bid forms, customers were requested to provide economic development impacts related to their incremental natural gas needs. Based on the feedback received through the 2023 EOI process (75% of bids provided feedback), a total of 6,900 jobs could be created through the greenhouse business growth enabled by the incremental capacity of the proposed Project. In addition, the total direct capital investment into their business operations in Southwestern Ontario indicated by customers on the bid forms exceeded $4.5 billion.[16]

20. Natural gas is uniquely suited to the greenhouse sector. It is used both to heat greenhouses and to supply the carbon dioxide requirements (“CO_2”) of the growing

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[13] EB-2022-0157, Transcript, Vol 3 (November 15, 2023), p. 132.
[14] EB-2022-0157, Transcript, Vol 3 (November 15, 2023), p. 140.
[15] Exhibit B-1-1, p. 16.
[16] Exhibit B-1-1, p. 16.

plants. A common practice within the greenhouse sector is to capture the CO_2 that would normally be emitted into the atmosphere upon combustion of natural gas and to instead use it within the greenhouse where it is consumed by the growing plants, resulting in faster growth and increased production.[17]

21. The greenhouse sector does not currently have a viable economic alternative to replace natural gas for heat and CO_2 production.[18] This position was also endorsed by Dr. Petro who testified that neither biomass, geothermal energy, nor heat pumps are suitable alternative energy sources for large scale greenhouse operations.[19]

22. The main alternate fuels used for heating in the greenhouse sector are oil, diesel, and propane. These fuels are not only more expensive than natural gas and environmentally unfriendly but also prevent the greenhouse operations from using the CO_2 emissions within the greenhouse because other elements within the exhaust of these fuels will harm the plants. As a result, without natural gas, a more expensive and higher carbon intensive energy source would need to be procured for heat, and an alternative source of CO_2 would also be required to maintain production levels.[20]

23. Over one-third of greenhouse production costs are energy-related. If natural gas is not available, greenhouse customers will be forced to either rely on a more expensive alternative, which will threaten their competitiveness, or move their operations to other jurisdictions, such as the United States, where natural gas is available.[21]

24. Dr. McDiarmid, in Environmental Defence's evidence, provided information related to the technical viability of non-natural gas alternatives for greenhouses. The OEB

[17] Exhibit B-1-1, p.15.

[18] Exhibit B-1-1, p.15; see EB-2022-0157, Transcript, Vol 3 (November 15, 2023), p. 133-134.

[19] EB-2022-0157, Transcript, Vol 3 (November 15, 2023), pp. 133-134.

[20] Exhibit B-1-1, p.15.

[21] Exhibit B-1-1, p. 16, OGVG, Exhibit K3.2, (November 6, 2023), p.4.

should give no weight to that information as it is not applicable to the type of large-scale greenhouse operations that drive the need for the Project.

25. Throughout her evidence, Dr. McDiarmid makes references to various greenhouse operations but does not distinguish between (i) small-scale commercial greenhouses, and (ii) large-scale greenhouse operations, and gives no consideration to the technical feasibility or viability of the alternatives referenced in this regard. As corroborated by Dr. Petro's testimony, this distinction is critically relevant,[22] as the proposed Project is required to support the energy needs of multiple large-scale greenhouse operations, not small-scale commercial greenhouses. Small-scale commercial greenhouses are fundamentally different than large-scale greenhouse operations. Small-scale commercial greenhouses are generally used as retail nurseries, school greenhouses, or recreational facilities, and are generally smaller than 1 acre in size. Large-scale greenhouse operations are mass-market vegetable farming facilities that span many acres.[23]

26. Dr. Petro testified that geothermal heating and heat pumps are not feasible technology types to heat industrial greenhouses.[24] With respect to geothermal heating systems, and further to several investigations that have been carried out by greenhouse operators and manufacturers, no such system has been able to overcome the geological limitations in the Leamington-Kingsville area which include a high-water table and poor soil conditions requiring lateral systems and significant land.[25] Under these geological conditions, vertical geothermal loops are not technically feasible. Horizontal looping would require significant additional land which would be prohibitively expensive.[26] With respect to heat pumps, this technology is in its infancy for large-scale industrial operations and as such the extent of their effectiveness for such uses "is all theoretical."[27] Furthermore, neither

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[22] EB-2022-0157, Transcript, Vol 3 (November 15, 2023), pp. 133-134 and 169.
[23] EGI, Reply Evidence, November 3, 2023, p.11.
[24] See also OGVG, Exhibit K3.2, (November 6, 2023), p.2.
[25] EB-2022-0157, Transcript, Vol 3 (November 15, 2023), p.133.
[26] EB-2022-0157, Transcript, Vol 3 (November 15, 2023), p. 172.
[27] EB-2022-0157, Transcript, Vol 3 (November 15, 2023), p. 134.

of these technology types produce CO_2, which is a required input for economic greenhouse operations.[28] Neither Dr. McDiarmid nor Dr. Petro were aware of any instances where heat pumps were used as primary sources of heating for industrial greenhouses in Ontario.[29]

27. As noted in Enbridge Gas's Reply Evidence, none of the applications of natural gas alternatives referenced by Dr. McDiarmid were in any way applicable to the types of customers at issue in this Application.

28. Dr. McDiarmid's evidence states that biomass can be used as a direct replacement for natural gas in the greenhouse sector. Respectfully, Dr. McDiarmid's position is based on a theoretical analysis that fails to account for the practicable challenges associated with operating a biomass facility to heat an industrial greenhouse. Dr. Petro's factually based evidence on the matter should be given more weight. Dr. Petro testified that while several greenhouse operators heat their greenhouse facilities with biomass-generated electricity, the biomass is used as a secondary fuel source to natural gas.[30] Dr. Petro explained that this is because biomass introduces challenges such as the reliable procurement and transport of biomass fuel and the requirement for additional land to store the biomass fuel. Further, there are additional costs associated with mitigating these and other challenges introduced by biomass. In response to Commissioner Dodds's inquiry about the practicable viability of biomass in the circumstances, Dr. McDiarmid conceded that her analysis was limited to "technically feasible solutions" and that she was of the view that biomass as a replacement continues to be economically challenging.[31]

29. Enbridge Gas further submits that the OEB should not consider Dr. McDiarmid as an expert in heating alternatives for the greenhouse sector. There is no aspect of her filed CV that relates to the application of heat pumps for the greenhouse sector. Dr.

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[28] EB-2022-0157, Transcript, Vol 3 (November 15, 2023), p. 134.

[29] EB-2022-0157, Transcript, Vol 1 (November 13, 2023), p. 96; EB-2022-0157, Transcript, Vol 3 (November 15, 2023), Vol 3, p. 173.

[30] EB-2022-0157, Transcript, Vol 3 (November 15, 2023), p.133.

[31] EB-2022-0157, Transcript, Vol 1 (November 13, 2023), pp. 106-107.

McDiarmid confirmed that she does not hold any designation as a Professional Engineer or as a professional that deals with soil conditions or the design for heat pumps in those soil conditions, and has no designation or technical expertise with respect to the design of heat pump systems for buildings.[32] Dr. McDiarmid testified that she does not purport to be an expert on greenhouse operations, and heating and cooling of greenhouses.[33]

30. Environmental Defence submitted that Dr. McDiarmid's evidence consists of evidence of fact rather than expert opinion evidence.

> "… Environmental Defence expects that Dr. McDiarmid will only be providing factual evidence with respect to greenhouse heat pumps, not evidence that would properly be characterized as expert opinion. This evidence will be based on third party information, which will be clearly identified. We therefore do not anticipate needing to qualify Dr. McDiarmid as an expert specifically in relation to heat pumps for greenhouses. …
>
> We have described Dr. McDiarmid's potential evidence relating to greenhouses as "high level comments on electric ground source heat pumps as an alternative option for new construction greenhouses."[34]

Dr. McDiarmid's testimony clarified that the basis of her proposed evidence consists of conducting a literature review on greenhouse heating, and that the basis of her participation in the present proceeding is to present the literature which forms the basis of her "opinion" while providing external references.[35]

31. Dr. McDiarmid's testimony in this regard consists of a vehicle for the provision of third-party information and a recitation by Dr. McDiarmid of facts in regard to which Dr. McDiarmid may not have the ability to fully respond to questions as to their factual accuracy, completeness or implications. As such, in the circumstances, the OEB should accord no weight to Dr. McDiarmid's evidence for her failure to qualify as an expert on the subject matter of her opinion evidence.

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[32] EB-2022-0157, Transcript, Vol 1 (November 13, 2023), p. 98.
[33] EB-2022-0157, Transcript, Vol 1 (November 13, 2023), p. 78.
[34] Correspondence from Environmental Defence, EB-2022-0157 (October 4, 2023).
[35] EB-2022-0157, Transcript, Vol 1 (November 13, 2023), p. 77.

(b) Power Generation

32. The IESO's 2022 Annual Planning Outlook ("APO") electricity demand forecast anticipates a rise in the average growth of electricity demand in Ontario, reaching about 1.9% annually compared to 1.7% in the 2021 forecast.[36] Due to the demand growth, along with nuclear retirements/refurbishments and expiring generation contracts, the IESO is anticipating electricity capacity shortfalls by the mid-2020s.

33. On October 6, 2022, Ontario Minister of Energy Todd Smith issued a Minister's Directive to the IESO to procure approximately 4,000 MW of capacity, with up to 1,500 MW of natural gas-fired generation, to ensure the reliable operation of Ontario's electricity system in response to ongoing and growing electricity needs expected in the future.[37] The Minister's Directive noted the IESO's 2021 finding that natural gas-fired generation plays an important role in the near term to avoid rotating blackouts.

34. Following the Minister's Directive, the IESO stated that it will seek to secure the new capacity through long-term procurement processes with in-service dates ranging from 2025 to 2027.[38] The IESO also re-iterated that without new natural gas-fired generation in the near term, the IESO would be reliant on emergency actions such as conservation appeals and rotating blackouts to stabilize the grid.

35. As per the IESO, the Brighton Beach Generating Station ("BBGS") will play a particularly critical role in meeting localized power generation needs between 2024 and 2028. With demand for electricity continuing to grow, it is anticipated that BBGS will continue to play a significant role in maintaining energy reliability in the region and will serve increased peak period electricity demand growth in the Southwest Region beyond 2028.[39]

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[36] Exhibit B-1-1, p. 17.
[37] Exhibit B-1-1, p. 17.
[38] Exhibit B-1-1, pp. 17-18.
[39] Exhibit B-1-1, p. 18.

36. In January 2023, Windsor City Council voted to support an energy proposal from Capital Power to pursue an expansion at its existing East Windsor Cogeneration Centre location related to the above mentioned IESO procurement.[40] The IESO's May 16, 2023, Resource Adequacy Update highlighted that the East Windsor Cogeneration Centre location was awarded an incremental 100 MW contract.

2. Current Panhandle System Pressure Bottlenecks

37. Because of the incremental natural gas demand, system demand will exceed system capacity (a system shortfall) on the Panhandle System commencing in Winter 2023/2024. The Panhandle System's capacity is limited by pressure bottlenecks along certain segments of the transmission system where the diameter of the pipeline is too small to flow the required volume, causing friction-related pressure losses. The most effective solution to eliminate a forecasted system shortfall are those that alleviate the relevant pressure bottlenecks.[41]

38. There are currently two major pressure bottlenecks along the Panhandle System. The NPS 20 Panhandle Line between Dover Transmission Station and Comber Transmission Station is currently the largest bottleneck on the Panhandle System. The next largest bottleneck on the Panhandle System is the pressure loss between the NPS 20 Panhandle Line and the Leamington-Kingsville market.[42] Figure 1 provides a map illustrating the location of these pressure bottlenecks in the Panhandle Market.

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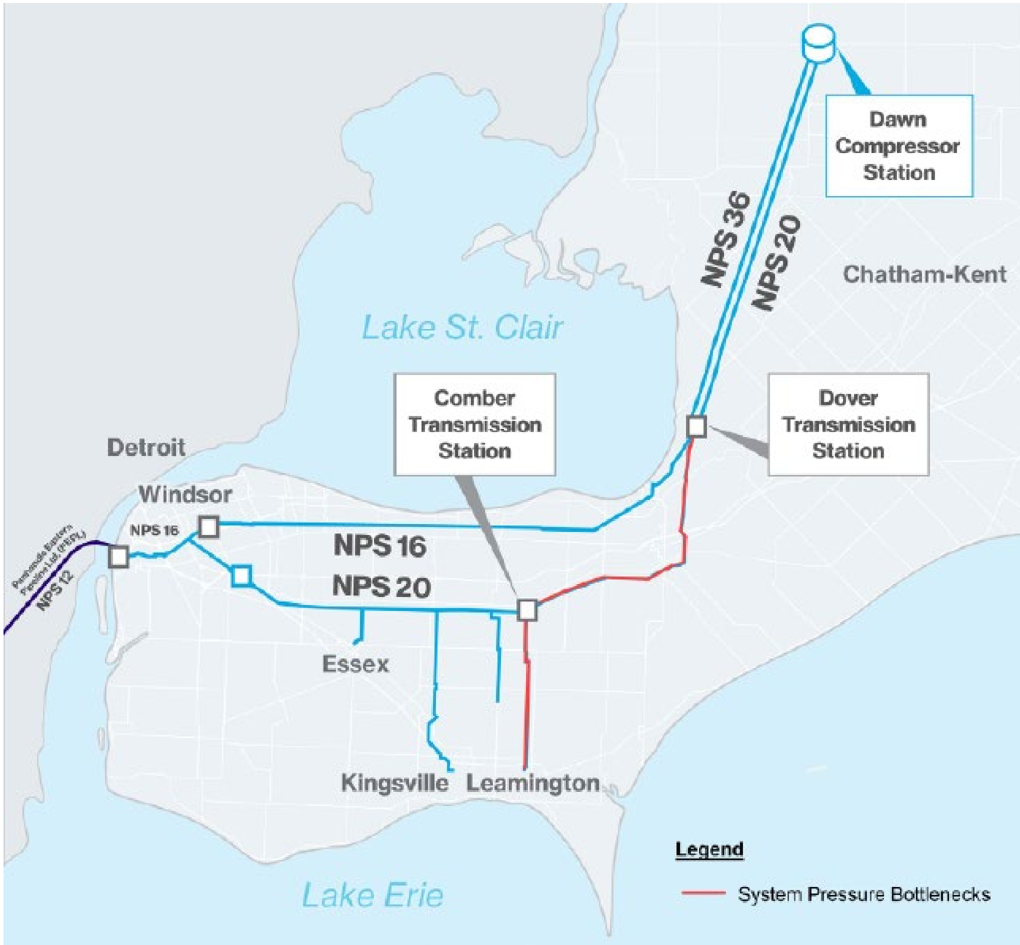
[40] Exhibit B-1-1, p. 18

[41] Exhibit B-2-1, p. 13.

[42] Exhibit B-2-1, p. 13.

Figure 1: Panhandle System Current Pressure Bottlenecks[43]



39. The system capacity in Winter 2024/2025 is forecasted to be 737 TJ/d and the firm customer demands are 802 TJ/d, resulting in a capacity shortfall of 66 TJ/d. Serving this demand without relieving the pressure bottleneck on the NPS 20 Panhandle Line between Dover Transmission Station and Comber Transmission Station would result in Enbridge Gas not meeting its operational requirements to serve existing customers.

40. The existing Panhandle System would not maintain the required contracted minimum delivery pressure of 1,724 kPag to BBGS. Specifically, the minimum inlet pressure to the BBGS customer station must be maintained at or above 1,827 kPag

[43] Exhibit B-2-1, p. 14.

to be able to deliver the 1,724 kPag minimum contracted delivery pressure required by the customer. The results of the network analysis show the inlet pressure to BBGS is 1,481 kPag which is less than required. In addition, the network analysis shows that the minimum inlet pressure to the Leamington North Gate station is 1,580 kPag which is below the required minimum inlet pressure of 2,275 kPag.[44]

41. Given the Panhandle System demand forecast, Enbridge Gas's Panhandle System network analysis indicates that the operational requirements of the Panhandle System cannot be met for Winter 2024/2025. This is based on the forecast Design Day demand of 802 TJ/d and no changes to the Panhandle System capacity. To continue to provide reliable firm service to new and existing general service and contract rate customers, Enbridge Gas must address this forecasted shortfall beginning November 1, 2024. The optimal solution to address the forecasted shortfall is the Project, which targets the largest pressure bottleneck on the current Panhandle System (i.e., between Dover Transmission Station and Comber Transmission Station).[45]

C. The Project and Project Alternatives

42. The Project is the best alternative to satisfy the project need. The Project provides 168 TJ/d of incremental Panhandle System capacity at an estimated cost of $358.0 million, with in-service dates of November 1, 2024, for the NPS 36 pipeline and related ancillary infrastructure. The Project provides market assurance that there will be sufficient capacity to meet the growing firm demands for natural gas service along the Panhandle System for the next five years.

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[44] Exhibit B-2-1, p. 15.
[45] Exhibit B-2-1, pp.15-16.

1. The Project

(a) Loop Existing NPS 20 Panhandle Line west of Dover Transmission Station

43. To address the pressure bottleneck between Dover Transmission Station and Comber Transmission Station, Enbridge Gas determined the length and diameter of the proposed pipelines based on the following considerations:

a. The new pipeline should provide enough system pressure to maintain system constraints for at least 5-years of forecast growth; and,

b. The project should result in new station or tie-in facilities that are adjacent to existing roadways and in locations easily accessible for vehicle access which also limits environmental impacts since new roads and power infrastructure would not be needed.[46]

44. Enbridge Gas determined that approximately 19 km of NPS 36 is required to partially alleviate the pressure bottleneck while satisfying the criteria above. Constructing the NPS 36 to Richardson Sideroad is sufficient to meet the 5-year growth forecast while providing the most cost-effective option with the lowest cost per unit of capacity. Furthermore, extending the existing NPS 36 Panhandle Line from Dawn through to Comber Transmission Station at the same diameter will reduce overall system costs for operations and maintenance since a common pipe size for the proposed Project (NPS 36) benefits the system from a maintenance perspective by avoiding costs associated with multiple pipeline inspection programs.

45. The Project provides many benefits and, based on the Assessment Criteria as defined below, is the best alternative for meeting the demonstrated need:

Economic Feasibility:

- Provides the lowest cost per unit of capacity relative to all other alternatives assessed.

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[46] Exhibit C-1-1, p. 8.

Timing:

- Provides market assurance in meeting the growing firm demands along the Panhandle System for the next five years.
- Can meet required November 1, 2024, in-service date.

Safety & Reliability:

- Positions the Panhandle System and the distribution pipelines connecting to it to meet forecasted long-term growth in the most efficient manner.
- Partially alleviates the largest bottleneck on the Panhandle System, increasing the reliability of service for existing customers and allowing for growth for both existing and new customers.

Risk Management:

- Scalable with future system growth.
- Directly serves area of growth and the Panhandle Market.

Environmental and Socio-economic Impact:

- Minimizes project impact by paralleling existing right of way.[47]

Project Alternatives

46. Enbridge Gas conducted an alternatives assessment to determine the optimal solution to meet the identified system need. The alternatives assessment evaluated facility alternatives and Integrated Resource Planning Alternatives (“IRPAs”), including supply-side IRPAs (e.g., 3rd party exchange service), demand-side Enhanced Targeted Energy Efficiency (“ETEE”), and hybrid facilities with IRPA alternatives.[48] The assessment determined the Project is the optimal solution to meet the identified system need.

[47] Exhibit C-1-1, pp. 21-22.
[48] Exhibit I.STAFF.7.

47. Enbridge Gas assessed each alternative, including the Project, using the following criteria (together, the “Assessment Criteria”):

<u>Economic Feasibility (Quantitative):</u> The alternative must be cost-effective compared to other alternatives, using the metrics of total cost, cost per unit of capacity and net present value (“NPV”).

<u>Timing (Quantitative):</u> The alternative must meet the growing firm demands on the Panhandle System for the next five years; and meet the required in-service date (November 1, 2024) to accommodate customer needs.

<u>Safety & Reliability (Qualitative):</u> The alternative must provide reliable and safe delivery of firm natural gas volumes to Enbridge Gas’s customers on the coldest winter day on the Panhandle System by meeting the Panhandle System Design Criteria.[49]

<u>Risk Management (Qualitative):</u> The alternative should not contain material risks relative to other alternatives. Enbridge Gas considered: (i) *Price risk:* the risk that the price or cost of the alternative may increase once that alternative has been deployed, and (ii) *Availability:* the risk that the alternative may become unavailable to meet the identified system need.

<u>Environmental and Socio-economic Impact (Qualitative):</u> The alternative should minimize impacts to Indigenous peoples, municipalities, landowners, and the environment relative to other viable alternatives.[50]

2. Facility Alternatives

(a) Upsize of existing NPS 16 Panhandle Line or NPS 20 Panhandle Line west of Dover Transmission

48. The Company considered increasing the diameter of either the NPS 16 Panhandle Line or the NPS 20 Panhandle Line west of Dover Transmission Station. Under this alternative, Enbridge Gas would employ a “lift and lay” construction process to increase the diameter of an existing segment of the Panhandle System. A similar approach was feasible in the 2017 Panhandle Reinforcement Project because the NPS 16 Panhandle Line between Dawn and Dover Transmission ran in close proximity to the NPS 20 Panhandle Line and could be replaced with an NPS 36 line where practicable. This allowed the NPS 16 Panhandle Line connected stations or

[49] Exhibit B- 2-1.

[50] Exhibit C-1-1, pp. 3-4.

customers to be moved to the NPS 20 Panhandle Line during construction. In contrast, in the current circumstance, the NPS 16 Panhandle Line and the NPS 20 Panhandle Line diverge west of Dover Transmission where the two pipelines are approximately 9 km apart from one another and therefore the same ability to maintain customer connection is not possible without requiring further infrastructure.

49. Also, Enbridge Gas evaluated a lift and lay of the NPS 20 Panhandle Line west of Dover Transmission and found it was not a viable alternative. The NPS 20 Panhandle Line cannot be replaced as it is required to serve customers at all times of the year. The NPS 16 Panhandle Line cannot serve system demands on its own, even during periods of low demand in the summer.[51] As a result, reliable service to customers could not be maintained during the construction period while the NPS 20 Panhandle Line would be out of service.

50. Enbridge Gas also evaluated upsizing the NPS 16 Panhandle Line west of Dover Transmission, which would require moving as many as nine downstream system connections from the NPS 16 Panhandle Line to the NPS 20 Panhandle Line and constructing a new interconnecting pipeline between the NPS 16 Panhandle Line and the NPS 20 Panhandle Line. In any event, upsizing of the NPS 16 Panhandle Line would not directly address the Panhandle System pressure bottleneck on the NPS 20 Panhandle Line between Dover Transmission and Comber Transmission Station discussed above.[52]

(b) New LNG Plant

51. Enbridge Gas deemed this alternative to be financially infeasible and did not assess it further since previous evaluations of the construction and operation of an LNG storage facility had estimated costs of $287 million (approximately $390 million in today's dollars) with about $5 million in annual operating expenses to address 106 TJ/d of system growth. This would only provide a portion of the capacity required.

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[51] Exhibit C-1-1, pp. 6-7.
[52] Exhibit C-1-1, pp. 6- 7.

Enbridge Gas expects the cost of an LNG solution to be 50% to 80% more than the estimated costs in previous evaluations that contemplated lower capacity needs.[53.]

3. Non-Facility Alternatives

(a) Integrated Resource Planning ("IRP")

52. The OEB's IRP Framework[54] provides Binary Screening Criteria in order to focus on situations where there is reasonable expectation that an IRPA could technically and economically meet a system need. The Binary Screening Criteria were applied, and it was determined that the need underpinning the Project must be met within three years; therefore, Enbridge Gas evaluated supply-side alternatives both alone and in combination with an enhanced targeted energy efficiency ("ETEE") IRPA to determine if implementation of these alternatives could meet the need within the required timeframe. The supply-side and ETEE alternatives assessed did not meet the growing needs of the Panhandle System from a technical and/or financial feasibility perspective.[55]

53. In 2021, Enbridge Gas engaged Posterity Group ("Posterity") to evaluate whether an ETEE IRPA could viably meet the identified system need or reduce the scope of the facilities that would otherwise be required.

54. Enbridge Gas engaged Posterity again in 2023 to assess whether including the Windsor and Chatham areas, in addition to the Leamington area (which was the geographic scope of the original ETEE IRPA analysis), would result in a technically feasible ETEE IRPA in relation to the proposed Project.[56] The analysis focused on assessing the extent to which an ETEE IRPA could eliminate or reduce the scope of the NPS 36 Panhandle Loop.

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[53] Exhibit C-1-1, p. 10.

[54] Decision and Order for Enbridge Gas' Integrated Resource Planning Framework Proposal (EB-2020-0091).

[55] Exhibit C-1-1, p. 2.

[56] Exhibit C-1-1, Attachment 3.

55. As noted in Posterity's June 5, 2023, report, a maximum peak hour reduction potential of approximately 72,000 m3/hour (57 TJ/d) from general service customers could be obtained by Winter 2029/2030 and would cost approximately $468 million. This results in $8.2 million per TJ, whereas the preferred alternative provides capacity at a cost of $2.13 million per TJ. Further, the potential peak hour reduction of 57 TJ/d is only achievable by Winter 2029/2030. The required capacity is 66 TJ/d by Winter 2024/2025 and increases to 112 TJ/d by Winter 2025/2026.

56. Because there is an insufficient amount of ETEE peak demand reduction potential from the general service customer base (alone or in combination with a supply-side alternative) to eliminate or reduce the scope of the facility, an ETEE IRPA is not a technically feasible alternative.[57]

(b) Firm exchange between Dawn and Ojibway

57. It is important to note that commercial alternatives, such as peaking supply transactions, delivered supply transactions, exchanges, and third-party transportation capacity assignments, are dependent on the agreed contractual terms and, therefore, should be assessed on a case-by-case basis.

58. Enbridge Gas considered a third-party firm exchange between Dawn and Ojibway whereby natural gas received at Ojibway would be used to serve in-franchise customers in exchange for natural gas delivered at Dawn to the third-party. An exchange would reduce the physical natural gas flow from Dawn to Ojibway on the Panhandle System.

59. However, no third-party commercial services are available for contract at Ojibway sufficient to eliminate the forecasted 5-year Panhandle System shortfall. 108 TJ/d of annual capacity is operationally available for delivery to Ojibway, but 60 TJ/d is already contracted by Enbridge Gas to serve firm design day demands. Of the remaining 48 TJ/d of capacity, 37 TJ/d is contracted by ROVER until October 31,

[57] Exhibit C-1-1, pp. 20-21.

2026, with evergreen renewal rights.[58] Enbridge Gas currently estimates that only 18 - 21 TJ/d of incremental firm annual capacity is available for deliveries to Ojibway into the Panhandle System.[59]

60. To confirm this assessment, Enbridge Gas issued a formal Request for Proposal ("RFP") for a Firm and Obligated Call Option Exchange Service beginning between November 1, 2023, and November 1, 2024 (later start dates were also considered up to 2026).[60]

61. During the RFP, Enbridge Gas approached the existing C1 Ojibway to Dawn shipper, ROVER, to determine interest in participating in the RFP. ROVER indicated no interest in providing the service, as ROVER is a transmission pipeline operator that transports gas for other shippers, and it does not hold title to the natural gas that is transported through its system. Since ROVER shippers do not have Ojibway as a delivery point as part of their service, ROVER shippers cannot specify the physical delivery path to get to Dawn. ROVER did not bid in the RFP.[61]

62. Only one market participant responded to the RFP. The bid received was subject to available capacity on the PEPL system, which was estimated by the bidder to be 19 TJ/d. In addition, on June 1, 2022, the PEPL website indicated that up to 21 TJ/d of delivery capacity was available at Ojibway.[62] Based on the RFP results and the available PEPL system capacity, it was confirmed that a firm exchange to Ojibway is not commercially available to defer the need for the Project or eliminate the 5-year capacity need.

63. A firm exchange is not commercially available to defer the need for the Project to Winter 2025/2026. On June 1, 2023, the PEPL website indicated that up to 21 TJ/d of delivery capacity was available at Ojibway. The available PEPL system capacity

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[58] Exhibit C-1-1, p. 11; and Transcript, Vol 2 (November 14, 2023), p. 88.
[59] Exhibit C-1-1. p. 11; Exhibit B-2-1; and Exhibit B-3-1.
[60] Exhibit C-1-1, pp. 15-16 and Attachment 1.
[61] Exhibit C-1-1, p. 14.
[62] Exhibit C-1-1, pp. 15-16.

with delivery to Ojibway did not change since the RFP was conducted. Therefore, Enbridge Gas did not complete a second RFP and did not evaluate this alternative further.[63]

(c) Hybrid Alternatives – Firm exchange between Dawn and Ojibway, looping of the NPS 20 Panhandle Line west of Dover Transmission

64. Given that the capacity requirement cannot be met through Ojibway delivered supply, Enbridge Gas considered the potential to utilize delivered supply to reduce the pipeline facilities needed to meet the 5-year forecast growth. The evaluation included a hybrid alternative which includes a 21 TJ/d firm exchange between Dawn and Ojibway beginning November 1, 2024, with a 40-year term, coupled with an NPS 36 loop of the NPS 20 Panhandle Line. The results showed that the incremental 21 TJ/d's impact on the length of the NPS 36 loop would be relatively small, which would result in the reduction of 1.07 km and an endpoint being located in the middle of a landowner's agricultural property.[64]

65. It is not typical to construct pipeline tie-ins beyond the edge of property-lines or roadways since it is important to have access for maintenance and connection to required utility services. Furthermore, locating pipeline tie-ins in the middle of an agricultural property would result in larger impacts to the landowner (i.e., installation of driveways, power infrastructure, etc.). Enbridge Gas found that shortening the loop to the nearest point of access would not provide the necessary capacity to meet the 5-year forecasted system shortfall when combined with the 21 TJ/d exchange between Dawn and Ojibway.[65]

66. In any event, this alternative is uneconomic relative to the Project even if Enbridge Gas proceeded to locate a pipeline tie-in in the middle of the agricultural property. This 1.07 km reduction in the length of the loop would decrease the Project cost by $7 million. To achieve this scope reduction, Enbridge Gas estimated that the firm

[63] Exhibit C-1-1, p. 16.
[64] Exhibit C-1-1, pp. 16-17.
[65] Exhibit C-1-1, pp. 16-17.

exchange would cost $4.2 million annually for an estimated discounted total cost of $66.2 million over a 40-year term.[66]

67. Enbridge Gas evaluated a second hybrid alternative which includes a 21 TJ/d firm exchange between Dawn and Ojibway beginning November 1, 2024, for a 40-year term coupled with a shorter NPS 36 loop of the NPS 20 Panhandle Line, ending at Wheatley Road. This tie-in location is 16.20 km west of Dover Transmission (2.73 km shorter than the preferred alternative).[67]

68. This hybrid alternative provides 15 TJ/d less capacity compared to the Project, does not provide enough capacity to serve the 5-year forecast growth, and is not economic relative to the Project. This 2.73 km reduction in the length of the loop would decrease the proposed Project cost by $27.5 million. To achieve this scope reduction, Enbridge Gas estimated that the firm exchange would cost $4.2 million annually for an estimated discounted total cost of $66.2 million over a 40-year term.[68]

69. In addition to the foregoing, the commercial availability, economic viability, flexibility, and reliability of these hybrid alternatives depend on various market factors including price, term, and capacity uncertainty. These factors pose risks to Enbridge Gas customers. There is future price risk with respect to exchange services since the service contains price variability compared to facility alternatives which have a fixed cost once installed. The value of the exchange service is generally based on the relative difference in gas commodity price between Dawn and Ojibway. Natural gas prices are subject to change based on market factors over time. With respect to renewal risk, a firm exchange service at Ojibway would require firm upstream transportation capacity on the PEPL system, and the provider of a firm exchange service would be exposed to renewal risk of their firm capacity agreement with

[66] Exhibit C-1-1, p. 17.
[67] Exhibit C-1-1, p. 17.
[68] Exhibit C-1-1, p. 17.

PEPL. This risk would be passed on to Enbridge Gas through similar renewal provisions in the exchange agreement.[69]

D. Project Costs & Economics

70. The Project costs are reasonable. The total estimated cost of the Project is $358.0 million.[70] Excluding indirect overheads, the total estimated cost of the Project is $289.2 million.

71. The cost is a class 3 estimate prepared in Q1 2023 and updated to reflect market conditions based on contractor responses to the RFP in Q4 2022, as per American Association of Cost Engineers ("AACE") standards and include a contingency of approximately 8% applied to all direct capital costs. The cost reflects the detailed engineering design stage of the Project and materials received to date. This contingency amount has been calculated based on an established contingency estimating methodology based on AACE® International RP 10S-90 recommended practice which considers the risk profile of the Project and is consistent with contingency amounts calculated for projects in similar stages of design and complexity completed by Enbridge Gas.[71]

72. 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. The use of E.B.O. 134 for the Project is also consistent with recent expansions to Enbridge Gas's Panhandle System approved by the OEB.[72]

73. Table 2 sets out the NPV calculated for the 3-Stage economic analysis completed for the Project.

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[69] Exhibit C-1-1, pp. 18-19.

[70] Exhibit E-1-2. Project cost is inclusive of (i) materials; (ii) labour; (iii) external permitting and land; (iv) outside services; (v) contingencies; (vi) interest during construction; and (vii) indirect overheads.

[71] Exhibit E-1-1, p.1; See Undertaking J3.5.

[72] Union Gas Panhandle Reinforcement Project: EB-2016-0186, Union Gas Kingsville Transmission Reinforcement Project: EB-2018-0013.

Table 2: NPV Calculation[73]

Stage	NPV ($millions)
1	($150)
2	$226 to $353
3	$257
Total	**$333 to $460**

74. Based on the E.B.O. 134 assessment, the Project is in the public interest with a net present value of $333 million to $460 million.

75. A Stage 2 analysis was undertaken as the Stage 1 NPV is less than zero (negative $150 million). The Stage 2 analysis considers the estimated energy cost savings that accrue directly to Enbridge Gas in-franchise customers as a result of using natural gas instead of another fuel to meet their energy requirements. The Stage 2 analysis estimated the NPV of the energy cost savings to be in the range of approximately $226 million over a period of 20 years to $353 million over 40 years. A range is provided as the outcome can vary depending upon the assumptions for alternative fuel mix, energy use, fuel prices, and term.

76. The Stage 2 energy cost savings have only been calculated for the general service customer class. As noted above, it is reasonable to conclude that contract rate customers will not choose an alternative fuel if natural gas is not available to them. The non-availability of natural gas will cause contract rate customers to expand or move their operations to other jurisdictions, likely outside of Ontario, where their natural gas needs can be served.

[73] Exhibit E-1-1. p. 7.

77. With respect to Stage 3, the analysis determined that the Project's construction will provide direct and indirect economic benefits to Ontario estimated at approximately $257 million.[74]

78. As noted above, customers who submitted 2023 EOI bids were requested to provide economic development impacts related to their incremental natural gas needs. In the 2023 EOI bid responses, customers indicated that total direct capital investment in their business operations in Southern Ontario would exceed $4.5 billion.[75]

79. The construction of this Project will result in additional direct and indirect employment. There will be additional employment directly involved in the construction of the Project. In addition, there will be a trickledown effect on employment as the Project is estimated to create approximately 1,093 jobs.[76] Greenhouse customers indicated that a total of 6,900 jobs could be created through the investment into their business operations enabled by the incremental capacity of the Project.[77]

80. In Environmental Defence's evidence, Dr. McDiarmid misapplied the OEB's E.B.O. 134 economic test and relied on inappropriate simplifying assumptions, which results in a flawed outcome that cannot be relied upon to properly assess the economic feasibility of the Project. The E.B.O. 134 economic test is a cumulative three stage test designed to assess the economic impact of infrastructure projects such as the Project. Since its inception and as approved by the OEB, the E.B.O. 134 economic test is a cumulative three-stage economic test that measures the net benefits of a transmission system expansion, i.e., an assessment of the benefits associated with the pipeline compared to the costs associated with the pipeline.

81. Dr. McDiarmid's proposed Stage 2 economic analysis is not part of a cumulative three-stage economic assessment of the net benefits associated with the natural gas

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[74] Exhibit E-1-7.
[75] Exhibit B-1-1, p. 16.
[76] Exhibit E-1-7.
[77] Exhibit B-1-1, p. 16.

system expansion project. Instead, Dr. McDiarmid assesses an electrification scenario that assumes 100% of incremental general service residential and commercial premises use high efficiency all electric configurations as of year one of the proposed Project. Her analysis is formulized on the basis of a choice between electric heat pump and heat pump water heater appliances and that of natural gas furnaces and water heaters. The NPV values proposed by Dr. McDiarmid do not reflect the net benefits of the Project, but rather reflect the relative comparison of those appliances. Dr. McDiarmid embeds the outcomes of the customer energy bill impact analysis as a net cost between Stages 1 and 3 of the natural gas system expansion assessment (i.e., into Stage 2). This creates an inherent inconsistency among the stages of the E.B.O. 134 cumulative three-stage economic assessment. It is not appropriate to include the result of Dr. McDiarmid's assessment in the E.B.O. 134 economic evaluation since it is not consistent with and therefore not additive to the results of Stages 1 and 3 with respect to the pipeline in question.

82. Stage 2 assesses the net benefits that new general service customers realize by attaching to the natural gas system due to the incremental capacity provided by the transmission system expansion project that is the subject of the assessment.

83. Based on her flawed and unsubstantiated assumption (as noted below) that all incremental residential and commercial general service attachments would choose high efficiency all-electric configurations as of year one of the proposed Project, Dr. McDiarmid generates a negative NPV at Stage 2. However, Dr. McDiarmid's logic is flawed since if only all-electric configurations were chosen then there would be no benefit in Stage 2 to incremental general service customers from the natural gas expansion project and zero is the lowest result for Stage 2. In any event, Dr. McDiarmid's assumption of 100% adoption of all-electric configurations as of year one of the proposed Project is baseless and she has completed no study or can offer no support for the assumption made.[78] The alternative energy mix underpinning Enbridge Gas's Stage 2 calculation provides for a more appropriate alternative

[78] Exhibit ED-IRR-2.0 Staff.1.

energy mix.[79] Based on this alternative energy mix and even with the adoption of Dr. McDiarmid's assumption regarding the efficiency of high-efficiency electric end-use equipment, the 20-year Stage 2 NPV would be a positive $79 million.[80]

84. Furthermore, by including natural gas delivery charges as a cost in Stage 2 of the economic evaluation, Dr. McDiarmid assigns incremental revenues from the Project as a cost to the Project. This is in direct conflict with the OEB's historical approval of the use of E.B.O. 134, which considers incremental revenues as a benefit to the Project in Stage 1. Dr. McDiarmid's analysis negates benefits from the Project calculated in Stage 1, where revenues are treated as a benefit by reducing or eliminating potential subsidy.[81]

85. In contrast to the foregoing, while Dr. McDiarmid assumes that as of 2024 all general service customers would choose all-electric configurations, Dr. McDiarmid does not consider any corresponding electricity infrastructure costs notwithstanding that she agrees there will be costs of energy transition and electrification that must be borne in the system cost of electricity.[82] The result being that Dr. McDiarmid's analysis results are overstated and should not be relied upon.

86. In addition, Dr. McDiarmid readily acknowledges that the pace of energy transition will be driven by the changes in public policy and that those public policy changes will have a direct impact on her analysis. This was particularly noted by the sensitivity of her analysis to changes in carbon pricing.[83] No one can reasonably predict the course of change in energy transition or the policy changes that may be made either hastening or slowing its progress. Against this backdrop, Dr. McDiarmid's analysis is no more than a theoretical analysis based on conjecture and

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[79] Exhibit I-Staff-15(c)(ii).
[80] EGI, Reply Evidence, November 3, 2023, pp. 5-6.
[81] EGI, Reply Evidence, November 3, 2023, p. 6.
[82] EB-2022-0157, Transcript, Vol 1 (November 13, 2023), p. 102.
[83] EB-2022-0157, Transcript, Vol 1 (November 13, 2023), pp. 99-100.

should not form the basis of OEB's determination of the public interest of a critical and major infrastructure project.

87. Ignoring the basis of the E.B.O. 134 economic test and its OEB approved application, Dr. McDiarmid has developed a new economic test that is untested and inconsistent with the intent and purpose of the E.B.O. 134 economic test. This result must be considered on the very narrow basis of Dr. McDiarmid's expertise. Dr. McDiarmid has no financial designation and does not regularly model or evaluate the viability of large infrastructure projects. Even in the area where Dr. McDiarmid has some level of expertise that expertise is very limited. She has no designation or technical expertise with respect to the design of heat pump systems for a building of any kind and while she is familiar with NRCan's sizing guidelines, she is not an expert on their application.[84] With respect to determining the suitability of residential heat pumps for particular buildings, Dr. McDiarmid has only sufficient expertise to say that air source heat pumps can be installed in residential new construction homes. Based on the foregoing, Dr. McDiarmid's Stage 2 analysis should be given little weight.

E. Engineering and Construction

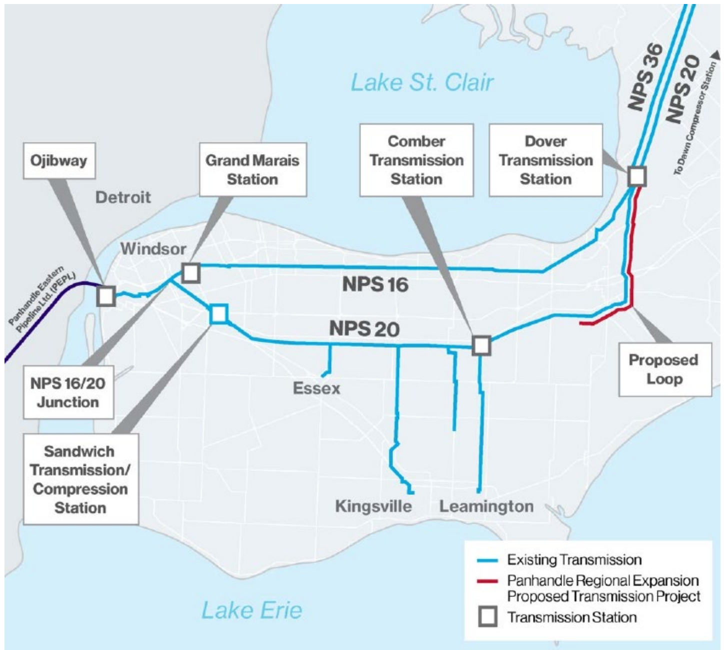
88. As noted above, and depicted in Figure 2, the Project includes construction of:

a. Approximately 19 km of NPS 36 natural gas pipeline, which will loop a portion of the existing NPS 20 Panhandle Line, from the existing Enbridge Gas Dover Transmission Station in the Municipality of Chatham-Kent to a new valve site in the Municipality of Lakeshore (the "Panhandle Loop"); and

b. Ancillary measurement, pressure regulation and station facilities within the Township of Dawn Euphemia and in the Municipality of Chatham-Kent.[85]

[84] EB-2022-0157, Transcript, Vol 1 (November 13, 2023), p. 98.
[85] Exhibit D-1-1, pp. 1-4.

Figure 2: Map of the Proposed Project Facilities[86]



89. The Project will be constructed and placed into service in two phases:

a. Construction of the Panhandle Loop and certain ancillary facilities (namely, Panhandle Take-off Station and Dover Transmission Station modifications, and the Richardson Sideroad Valve Site Station)[87] will be constructed starting in the first quarter of 2024 and placed into service by November 1, 2024; and

b. Construction of the Dawn Yard Upgrade[88] will be constructed starting in the second quarter of 2025 and placed into service by November 1, 2025.

90. The construction schedules for both phases of the Project are designed to take advantage of the drier summer months to minimize the impact of construction on agricultural lands and other features, such as watercourses.[89]

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[86] Exhibit D-1-1, p.2.
[87] See descriptions at Exhibit D-1-1, pp. 3-4.
[88] See description at Exhibit D-1-1, p. 3.
[89] Exhibit B-1-1, p. 21, para. 68.

91. Enbridge Gas will design, install, and test the Project facilities in accordance with specifications outlined in Enbridge Gas's Construction and Maintenance Manual (the "Specifications") and with the requirements of Ontario Regulation 210/01 (Oil and Gas Pipeline Systems) under the *Technical Standards and Safety Act, 2000*. The design meets or exceeds the requirements of CSA Z662 Standard for Oil and Gas Pipeline Systems (latest edition) in accordance with the Code Adoption document under the Ontario Regulations.[90] In addition, the Technical Standards and Safety Authority has completed its review of the Project design and, in its final review letter dated July 26, 2022, confirmed that all outstanding items have been addressed by Enbridge Gas.[91]

92. Enbridge Gas will construct the Project using qualified construction contractors and Enbridge Gas employees who will follow the Specifications and any site-specific conditions required for the Project, as established based on the findings in the Environmental Report.[92] In addition, all construction, installation and testing of the Project will be witnessed and certified by a valid Gas Pipeline Inspection Certificate Holder.[93]

93. The method of construction will be a combination of open trench and trenchless technology.[94] Restoration and monitoring will be conducted to ensure successful environmental mitigation for the Project.[95] After installation, the Panhandle Loop will be strength tested and leak tested using water as the test medium.[96]

94. Enbridge Gas will obtain all permits, authorizations, approvals, permanent easements and/or temporary easements if and to the extent required for the route

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[90] Exhibit D-1-1, p. 2, para. 9.
[91] Exhibit I-Staff-16.
[92] See Exhibit F-1-1, discussed in Part F of this AIC.
[93] Exhibit D-1-1, para. 10.
[94] See Exhibit D-1-1, paras. 11-14.
[95] Exhibit D-1-1, para. 11.
[96] Exhibit D-1-1, paras. 17-18.

and location of the relevant Project facilities prior to the commencement of each phase of construction.[97]

F. Environmental Matters

95. Enbridge Gas has undertaken a comprehensive route evaluation and environmental and socio-economic impact study for the Project, including a cumulative effects assessment, to select the preferred route and identify relevant impacts and mitigation measures where appropriate.[98] By following its standard construction practices and adhering to the recommended mitigation measures, the construction and operation of the Project will have negligible impacts on the environment. Moreover, no significant cumulative effects are anticipated from development of the Project.[99]

96. Led by the Company's consultant AECOM Canada Limited ("AECOM"), the study included a consultation program designed to solicit input from interested and potentially affected parties, including Indigenous communities. Input obtained through the consultation program was evaluated and integrated into the study.[100]

97. The results of the study are documented in an Environmental Report (the "ER").[101] The ER was prepared in conformance with the OEB's *Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario*, 7th Edition, 2016 (the "Guidelines").[102] The ER identifies the environmentally preferred routes for the proposed pipelines, as well as various mitigation and protective measures to minimize or eliminate potential impacts to the environment resulting from construction of the Project.[103] In May 2023 AECOM

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[97] Exhibit G-1-1, pp. 4-5, paras. 13-15.
[98] Exhibit F-1-1, p. 1, para. 3.
[99] Exhibit F-1-1, p. 3, para. 10.
[100] Exhibit F-1-1, p. 1, para. 3.
[101] A copy of the ER is provided in Exhibit F-1-1, Attachment 1.
[102] Exhibit F-1-1, p. 2, para. 4.
[103] Exhibit F-1-1, p. 2, para. 9.

confirmed that that the ER remains appropriate with respect to the 2023 updated Project scope.[104]

98. The ER was forwarded to the Ontario Pipeline Coordination Committee ("OPCC") on April 29, 2022 for review, and copies were sent to all affected municipalities, conservation authorities, landowners, Indigenous communities, and other local agencies.[105] In addition, virtual public information sessions were held to further inform and solicit input from landowners, tenants and the general public with respect to the Project.[106] In May 2023, Enbridge sent letters to OPCC members, affected municipalities, conservation authorities, landowners, Indigenous communities, and other local agencies advising of the 2023 updated Project scope and expected timeline for Enbridge Gas's updated application submission.[107] Summaries of the comments received, together with responses from Enbridge Gas and/or AECOM on its behalf, are provided in the Application.[108]

99. Enbridge Gas will comply with all mitigation measures recommended in the ER, including by developing an Environmental Protection Plan ("EPP") prior to construction. The EPP will incorporate the recommended mitigation measures from the ER and any additional recommendations or requirements from permitting agencies, as well as any additional mitigation measures identified and agreed upon with Indigenous communities. Those measures will be communicated to the construction contractor, and a qualified Environmental Inspector or suitable representative will be available to assist the Project Manager in seeing that the measures set out in the EPP are adhered to and that commitments made to the public, communities, landowners, and agencies are honoured.[109]

[104] Exhibit F-1-1, p. 2, para. 4.
[105] Exhibit F-1-1, p. 2, para. 4.
[106] Exhibit F-1-1, p. 2, para. 7. See also Exhibit I-Staff-17.
[107] Exhibit F-1-1, p. 2, para. 4
[108] See Exhibit F-1-1, Attachment 2 / Attachment 3.
[109] Exhibit F-1-1, p. 3, para. 9. See also Exhibit I-TFG-7 and JT1.13.

G. Land Matters

100. In total, the Panhandle Loop is approximately 19 km in length. Along the length of this line, Enbridge Gas requires an easement width of approximately 23 meters to ensure safety and to provide the necessary working space for maintenance purposes. This translates into a need for approximately 42.0 hectares (104 acres) to be secured by means of permanent easements for the Project facilities, as well as a need for approximately 71.6 hectares (177 acres) to be secured by means of temporary easements for purposes of construction and topsoil storage.[110]

101. Enbridge Gas has initiated meetings with all landowners from whom it requires either permanent or temporary easements, and will continue to meet with them in an effort to obtain options to acquire all the necessary land rights.[111] Enbridge Gas has offered or will offer to those landowners, as applicable, a permanent easement in the form of the Pipeline Easement Agreement provided at Exhibit G-1-1, Attachment 3, and/or a temporary easement in the form of the Temporary Land Use Agreement provided at Exhibit G-1-1, Attachment 4. The Pipeline Easement Agreement accommodates the installation, operation and maintenance of the proposed pipeline. The Temporary Land Use Agreement accommodates construction and restoration work over a two-year term. The forms of Pipeline Easement Agreement and Temporary Land Use Agreement proposed by Enbridge Gas have been previously reviewed and approved by the OEB.[112]

102. Enbridge Gas is implementing a comprehensive program to provide landowners, tenants and other interested parties with information regarding the Project. Information was previously distributed through correspondence and meetings with the public. Where formal public meetings were held, in conjunction with the ER (as discussed above), directly affected landowners and agencies were invited to

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[110] Exhibit G-1-1, p. 1, para. 4. See also Exhibit I-Staff-10, which provides a breakdown of the permanent and temporary land requirements for the Panhandle Loop.

[111] Exhibit G-1-1, p. 2, para. 6.

[112] For example, they are the same as those approved in respect of the Haldimand Shores Community Expansion Project (EB-2022-0088).

participate by letter, and the general public was invited to participate through social media, newspaper advertisements and radio.[113]

103. Enbridge Gas has also initiated meetings with landowners to obtain, and has generally been successful in obtaining, early access to enable the Company to perform survey work. To date, Enbridge Gas was successful in obtaining early access land rights and has entered into Easement and Temporary Land Use Agreements with 53 of the 56 affected property owners.[114]

104. Regarding the three affected properties for which Enbridge Gas has not been able to secure early access land rights or Easement and Temporary Land Use Agreements to date, Enbridge Gas notes that these properties are adjacent to one another and are owned by related parties which are under common control. While correspondence between Enbridge Gas and these related landowners began in January 2022, negotiations have not progressed to a stage where early access rights have been granted. As such, on June 16, 2023, concurrent with the filing of its amendments to the current Application, Enbridge Gas filed an application with the OEB (EB-2022-0285) under section 98(2) of the *Ontario Energy Board Act, 1998*, for an order authorizing entry onto the properties to complete necessary examinations and surveys.[115] On August 25, 2023 Enbridge Gas filed a letter with the OEB providing an update regarding the timing as set out in the early access application, and requested that the application be placed into abeyance.[116] On August 29, 2023 the OEB approved Enbridge Gas's abeyance request.[117] As per the OEB's direction within its August 29, 2023 correspondence, Enbridge Gas will file a status update regarding the abeyance request no later than December 31, 2023.

105. Enbridge Gas will also continue to pursue the necessary Easement and Temporary Land Use Agreements with the remaining landowners on a negotiated basis.

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[113] Exhibit G-1-1, p. 3, para. 9.
[114] Exhibit F-1-1, p. 3, para. 10.
[115] Exhibit G-1-1, pp. 3-4, para. 11.
[116] EB-2022-0285, Enbridge Gas Correspondence (August 25, 2023).
[117] EB-2022-0285, OEB Correspondence (August 29, 2023).

However, if leave to construct is granted and by such time the Company has not been able to conclude the required Easement and Temporary Land Use Agreements with these landowners, Enbridge Gas will need to seek leave from the OEB to expropriate such land rights pursuant to section 99 of the *Ontario Energy Board Act, 1998* so that it could complete construction of the Project.[118]

106. Given the uncertain timelines related to any expropriation proceeding that may be needed, the planned November 1, 2024, in-service date for the Project could potentially be impacted. In such a circumstance the Company proposes to employ a temporary contingency plan to ensure Winter 2024/2025 demands are met. The contingency plan would involve the Company installing a temporary tie-in to the east of the properties in question. The temporary tie-in would remain throughout Winter 2024/2025 and would be removed once the land matter is resolved.[119]

107. Enbridge Gas has a comprehensive and proven landowner relations program in place. Key elements of this program include complaint tracking and assignment of a land agent to: (i) ensure that commitments made to landowners are fulfilled; (ii) address landowner questions/concerns as promptly as possible; and (iii) act as a liaison between landowners, the Pipeline Contractor, and Enbridge Gas Project personnel.[120]

108. When Project restoration is completed, landowners will be asked to acknowledge if they are satisfied with the restoration. Enbridge Gas's receipt of such acknowledgement releases and allows for payment for clean-up on the property to the Pipeline Contractor. Enbridge Gas remains obligated to the landowner for tile repairs, compensation for damages and/or further clean-up as may be required due to erosion or subsidence directly related to pipeline construction.[121]

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[118] Exhibit G-1-1, p. 4, para. 12.
[119] Exhibit G-1-1, pp. 4, para. 13.
[120] Exhibit G-1-1, p. 5, para. 14.
[121] Exhibit G-1-1, p. 3, para. 15.

H. Indigenous Consultation

109. Enbridge Gas has developed and carried out a comprehensive and diligent process that reflects its strong commitment to meaningful engagement and dialogue with Indigenous groups (First Nations and Métis) that are potentially affected by the Project. Throughout this process, Enbridge Gas has strived to build an understanding of potentially affected interests, ensure regulatory requirements are met, mitigate or avoid impacts on Indigenous interests/rights, and provide mutually beneficial opportunities where possible.

110. The design of Enbridge Gas's Indigenous engagement program was based on adherence to the OEB's Guidelines and to Enbridge Inc.'s company-wide Indigenous Peoples Policy.[122]

111. In accordance with the OEB's Guidelines, Enbridge Gas provided the Ontario Ministry of Energy ("MOE") with a description of the Project on June 29, 2021, for the purpose of inquiring as to any duty to consult requirements.[123] On August 6, 2021, Enbridge Gas received a Delegation Letter from the MOE that delegated the procedural aspects of the duty to consult to Enbridge Gas for the Project and identified six Indigenous communities to be consulted in relation to the Project.[124] In addition, by email of the same date, the MOE advised the Company of the need to engage with an additional community as a best practice based on proximity.[125]

112. On April 20, 2022, Enbridge Gas provided an updated description of the Project to the MOE reflecting refinements made to the design and preferred route of the Project since the June 29, 2021, letter noted above. The MOE confirmed that no changes to the direction provided in the Delegation Letter were required as a result of the Project refinements.[126] On June 6, 2023, Enbridge Gas provided a further

[122] Exhibit H-1-1, p. 2, para. 8. See also Exhibit I-TFG-22.

[123] Exhibit H-1-1, p. 1, para. 3.

[124] Aamjiwnaang First Nation, Bkejwanong (Walpole Island) First Nation), Caldwell First Nation, Chippewas of the Thames First Nation, Chippewas of Kettle and Stony Point First Nation, and Oneida Nation of the Thames.

[125] Exhibit H-1-1, p. 2, para. 4. The additional community is Delaware Nation.

[126] Exhibit H-1-1, p. 2, para. 5.

updated description of the Project to the MOE reflecting changes made to the Project scope.[127]

113. Enbridge Gas provided its Indigenous Consultation Report ("ICR") to the MOE on June 10, 2022, and has subsequently corresponded with the MOE regarding its review process.[128] On June 10, 2023, Enbridge Gas provided an updated ICR to the MOE reflecting changes made to the Project scope.[129] The MOE will review Enbridge Gas's consultation with Indigenous groups potentially affected by the Project and provide its decision as to whether the Company's consultation has been sufficient by the end of the record closing.[130] Upon receipt of the MOE's decision regarding the sufficiency of Indigenous consultation on the Project, Enbridge Gas will file the sufficiency letter with the OEB.[131]

114. Enbridge Gas strives to achieve meaningful relationships with Indigenous groups by providing timely exchanges of information, understanding, and addressing Indigenous project-specific concerns, and ensuring ongoing dialogue regarding its projects, including potential impacts and benefits.[132]

115. Enbridge Gas conducted its Indigenous engagement for the Project through phone calls, in-person meetings, mail-outs, open houses, and email communications. During these engagement activities, Enbridge Gas representatives provided an overview of the Project, responded to questions and concerns, and addressed any interests or concerns expressed by Indigenous communities to appropriately avoid or mitigate any Project-related impacts on Indigenous or treaty rights. Capacity funding was offered to ensure there were reasonable resources for Indigenous communities to meaningfully participate in consultation. To accurately record engagement activities and ensure follow-up by either the Crown or Enbridge Gas,

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[127] Exhibit H-1-1, p. 2, para. 6.
[128] Exhibit I-Staff-22.
[129] Exhibit H-1-1, p. 2, para. 7.
[130] Exhibit I.STAFF.22, part d).
[131] Exhibit H-1-1, p. 2, para. 7.
[132] Exhibit H-1-1, p. 3, para. 9.

applicable supporting documents were tracked and documented.[133] In addition to filing detailed information regarding its consultation with Indigenous communities on the record of the OEB proceeding, Enbridge Gas has responded to written and oral questioning from certain Indigenous groups during the course of the OEB proceeding.[134.]

116. Enbridge Gas will continue to pursue meaningful dialogue and engagement with the identified Indigenous communities throughout the life of the Project to ensure impacts on Indigenous or treaty rights are appropriately addressed.[135]

I. Relief Requested

117. Based on the foregoing, Enbridge Gas respectfully requests that the OEB issue an Order granting leave to construct the Project pursuant to section 90 of the Act and an Order approving the forms of Pipeline Easement Agreement and Temporary Land Use Agreement set out at Exhibit G-1-1, Attachments 3 and 4, pursuant to section 97 of the Act.

133 Exhibit H-1-1, pp. 3-4, para. 11.
134 Exhibit H-1-1, p. 4, para. 12.
135 Exhibit H-1-1, p. 4, para. 13.