Ontario Energy Board | Commission de l'énergie de l'Ontario

Ontario

BY EMAIL

December 14, 2023

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

Dear Ms. Marconi:

Re: Ontario Energy Board (OEB) Staff Submission
Enbridge Gas Inc. (Enbridge Gas)
Panhandle Regional Expansion Project
OEB File Number: EB-2022-0157

Please find attached OEB staff's submission in the above referenced proceeding, pursuant to Procedural Order No. 8.

Yours truly,

Zora Crnojacki

Digitally signed by Zora Crnojacki
Date: 2023.12.14 15:17:22 -05'00'

Zora Crnojacki
Senior Advisor, Natural Gas Applications

Encl.

cc: All parties in EB-2022-0157

ONTARIO ENERGY BOARD

OEB Staff Submission

Enbridge Gas Inc.

Panhandle Regional Expansion Project

EB-2022-0157

December 14, 2023

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1 Application Summary

On June 10, 2022, Enbridge Gas filed an application seeking orders from the OEB under section 90(1) of the *Ontario Energy Board Act, 1998* (OEB Act), for leave to construct approximately 19 km of natural gas pipeline from its Dover Transmission Station in the Municipality of Chatham Kent to its existing pipeline in the Municipality of Lakeshore (Panhandle Loop[1]) (Project) and approximately 12 km of natural gas pipeline in the Municipality of Lakeshore, Town of Kingsville and the Municipality of Leamington (Leamington Interconnect).

Enbridge Gas also applied under section 97 of the OEB Act, for approval of the forms of agreement it offers to landowners to use their land for routing or construction of the proposed pipeline.

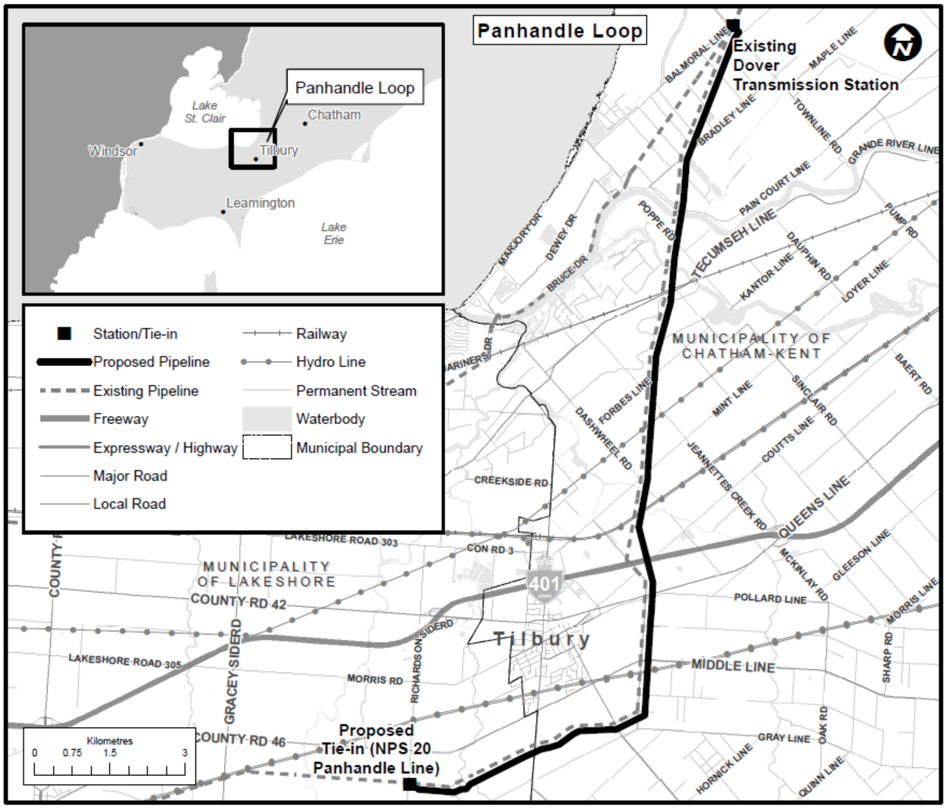
Enbridge Gas filed an amended application on June 16, 2023. In the amended application, Enbridge Gas stated that it reassessed the Project and decided to remove the Leamington Interconnect. Enbridge Gas also updated the Project demand forecast, Project construction and in-service schedules, the costs and economics and the other evidence affected by the changes in the Project's scope, schedule and costs.

Enbridge Gas proposed to commence construction of the Project in April 2024 with an in-service date of November 2024.[2]

A general location of the Project is shown in Figure 1 below.[3]

[1] Term "loop" is a common industry term used to mean paralleling an existing pipeline
[2] Exhibit D, Tab 1, Schedule 1, Attachment 1, updated
[3] Exhibit A, Tab 2, Schedule 1, Attachment 1, updated

Figure 1
Project Location

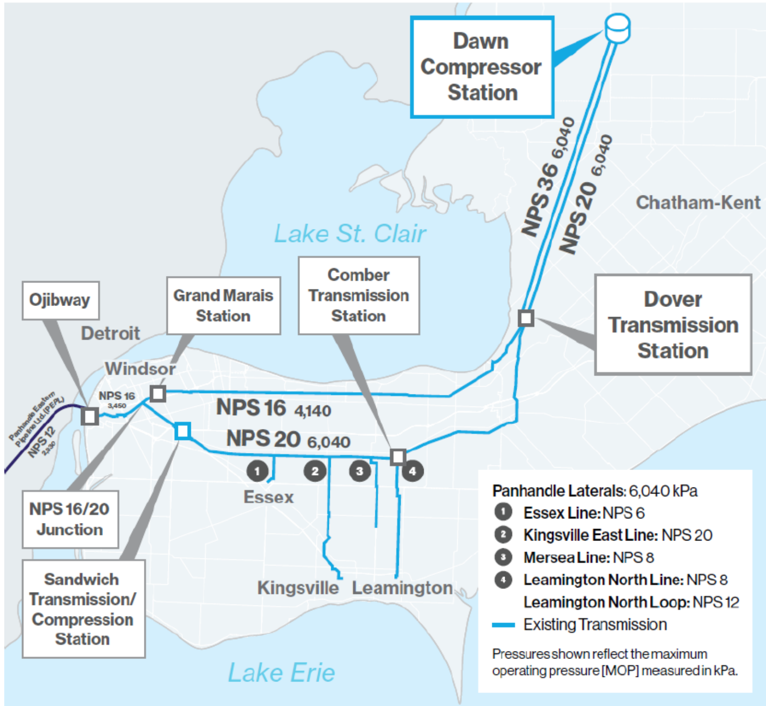


The Panhandle system is comprised of transmission pipelines to transport natural gas between Enbridge Gas's Dawn Compressor Station, located in the Township of Dawn-Euphemia and the Ojibway Valve Site, located in the City of Windsor.[4] The Panhandle system feeds distribution systems serving residential, commercial, and industrial markets in the municipalities of Dawn- Euphemia, St. Clair, Chatham-Kent, Windsor, Lakeshore, Leamington, Kingsville, Essex, Amherstburg, LaSalle, and Tecumseh.[5]

A diagram of the Panhandle system and the market area it supplies is provided in Figure 2 below.[6]

[4] Exhibit A, Tab 3, Schedule 1, page 1, paragraph 2
[5] Ibid.
[6] Exhibit B, Tab 2, Schedule 1, page 2, Figure 1, updated

Figure 2
Panhandle System and Market



According to Enbridge Gas, the firm demand for natural gas from new and existing general service and contract rate customers has continued to grow on the Panhandle system over the past decade. The Project is in response to continued increasing natural gas demand growth in the areas served by the Panhandle system. Since 2013, Enbridge Gas has completed six expansions[7] of the Panhandle system as shown in Figure 3 below.[8]

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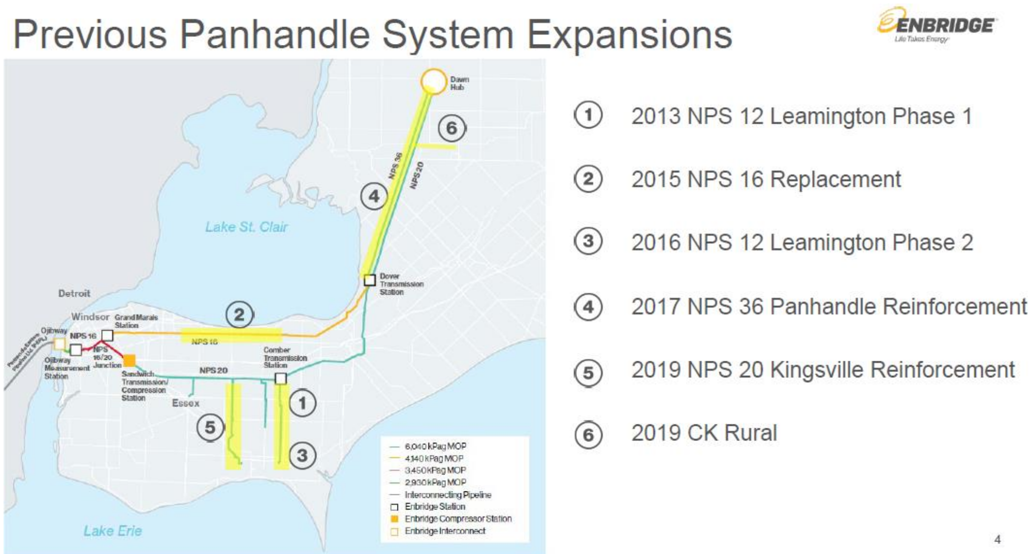
[7] EB-2012-0431, 2013 NPS 12 Leamington Phase 1; EB-2013-0420, 2015 NPS 16 Replacement; EB-2016-0013, 2016 NPS 12 Leamington Phase 2; EB-2016-0186, 2017 NPS 36 Panhandle Reinforcement; EB-2018-0013, 2019 NPS 20 Kingsville Reinforcement; EB-2018-0188, CK Rural Expansion
[8] Exhibit KT1.1 Enbridge Gas Technical Conference Presentation, page 4

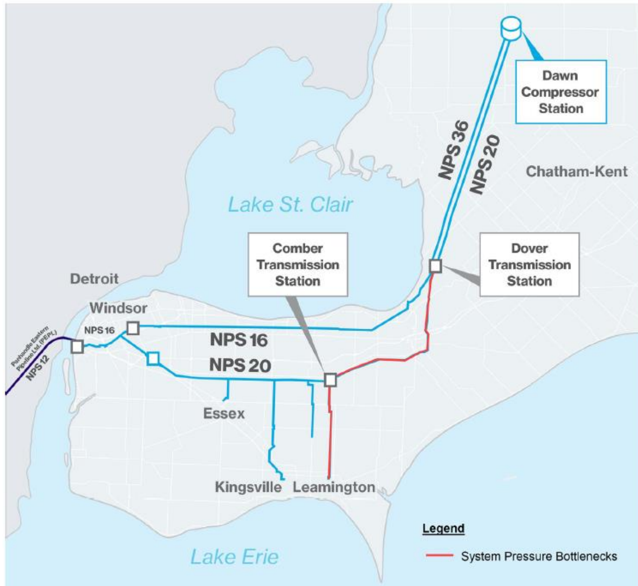
<u>Figure 3</u>
<u>Completed Panhandle System Expansions</u>



There are currently two major pressure bottlenecks along the Panhandle system: (1) the NPS 20 Line between the Dover Transmission Station and the Comber Transmission Station; and (2) the pressure loss between the NPS 20 Line and the Leamington-Kingsville market.[9] Figure 4 below illustrates the locations of the current Panhandle system pressure bottlenecks.[10]

[9] Exhibit B, Tab 2, Schedule 1, page 13, paragraph 31
[10] Exhibit B, Tab 2, Schedule 1, page 14, Figure 4, updated

Figure 4
Panhandle System Pressure Bottlenecks



OEB staff submits that the OEB should grant Enbridge Gas leave to construct the Project, subject to the OEB's standard conditions of approval appended as Schedule A to this submission.

OEB staff submits that Enbridge Gas has demonstrated that there is a need for the Project, the Project is the best option to meet the need, and the Project is economic under the OEB's E.B.O. 134 economic test. OEB staff submits that the E.B.O. 134 test is the appropriate economic test to apply to the Project. As explained in detail later, while the Project is best categorized as a "dual purpose" pipeline, OEB staff is of the view that the current proceeding is not the appropriate time to make changes to the OEB's approach to economic testing.

OEB staff submits that Enbridge Gas has completed the Environmental Report in accordance with the OEB's Environmental Guidelines for Location, Construction and Operation of Hydrocarbon Pipelines in Ontario [7th Edition, 2016] (Environmental Guidelines). OEB staff has no concerns with the environmental aspects of the Project as Enbridge Gas is committed to implementing the mitigation measures set out in the Environmental Report and obtaining all required permits and approvals.

Indigenous consultation and engagement has been ongoing. OEB staff is not aware of any outstanding concerns from Indigenous communities regarding any Aboriginal or treaty rights that may be impacted by the Project. OEB staff notes that Enbridge Gas has been following the protocol for procedural aspects of the consultation including requirements related to the Ministry of Energy's role in Indigenous consultation process as set out in the OEB's Environmental Guidelines. OEB staff submits that if the OEB determines that it is appropriate to grant Leave to Construct for the Project, the OEB should wait to receive the Letter of Opinion from the Ministry of Energy before providing its final approval. If the Ministry of Energy’s Letter of Opinion is not filed prior to record close, the OEB can place the proceeding in abeyance until such time that the letter is filed.

OEB staff also supports the approval of the forms of agreement for permanent easement and temporary land use proposed by Enbridge Gas.

2 The Proceeding

The OEB issued the Notice of Hearing on July 4, 2022. The following parties applied for and were granted intervenor status:

- Association of Power Producers of Ontario (APPrO)
- Atura Power
- Middle Road Farms Limited and Courey Corporation (Courey Corporation) (Joint intervention)
- Environmental Defence
- Energy Probe
- Federation of Rental-housing Providers of Ontario (FRPO)
- Industrial Gas Users Association (IGUA)
- Ontario Greenhouse Vegetable Growers (OGVG)
- Pollution Probe
- Three Fires Group
- School Energy Coalition (SEC)[11]
- Kitchener Utilities[12]

APPrO, Environmental Defence, Energy Probe, FRPO, IGUA, OGVG, Pollution Probe, SEC and Three Fires Group were also found to be eligible to apply for an award of costs.

On August 12, 2022, the OEB issued Procedural Order No. 1 which set the schedule for written discovery by interrogatories and for a transcribed technical conference. In Procedural Order No. 1, the OEB also ordered any intervenor seeking to file evidence to file a description of the proposed evidence and estimated cost of preparing the evidence. Environmental Defence and Courey Corporation responded by filing information on September 27, 2022.

Environmental Defence proposed to retain Dr. McDiarmid to review Enbridge Gas's Stage 2 analysis under E.B.O. 134 and provide an analysis of the net savings or net costs of customers using natural gas in comparison to alternatives, such as high efficiency electric heat pumps, focusing on residential customers.

Courey Corporation indicated that it planned to provide evidence on the need to extend the proposed Panhandle Loop west to terminate the pipeline on the properties of Courey Corporation and Middle Road Farms Limited. Corey Corporation also noted that Mr. Thibodeau may provide evidence and that a soil scientist may be required.

[11] Late intervenor status granted on August 17, 2023
[12] *Ibid.*

On September 27, 2022, Courey Corporation also clarified that it also represents Mr. Girard Thibodeau, a directly impacted landowner. On October 11, 2022, the OEB granted Mr. Girard Thibodeau intervenor status. The OEB also granted Courey Corporation, Middle Road Farms Limited, and Mr. Girard Thibodeau eligibility to apply for an award of costs.

Pollution Probe and Enbridge Gas responded to the intervenor evidence proposals on September 29, 2022. Pollution Probe supported Environmental Defence's proposed evidence. Enbridge Gas stated that it is not able to comment on the relevance of the proposed evidence and requested that if the OEB allows the proposed evidence, it also allows for the discovery and for Enbridge Gas to file reply evidence.

On October 3, 2022 and October 11, 2022, the OEB requested further clarification and information on the evidence proposed by Environmental Defence and Courey Corporation, respectively. On October 4, 2022, Environmental Defence responded to the OEB's questions. On October 5, 2022, Enbridge Gas objected to Environmental Defence's proposed evidence. Courey Corporation did not respond to the OEB's request.

The OEB held a two-day transcribed technical conference from October 6-7, 2022.

On October 14, 2022, the OEB issued Procedural Order No. 2, granting Environmental Defence and Courey Corporation's requests to file evidence and Enbridge Gas's request to file reply evidence. The OEB also granted Enbridge Gas's extension request to file written responses to undertakings on October 19, 2022, from October 14, 2022 as set out in Procedural Order No. 1.

Procedural Order No. 2 also set the schedule for the remainder of the proceeding including: intervenor evidence and Enbridge Gas's reply evidence, discovery on the intervenor and reply evidence, Enbridge Gas's argument-in-chief, OEB staff and intervenor written submissions and Enbridge Gas's reply submission.

On October 19, 2022, Enbridge Gas filed written responses to undertakings from the technical conference.

On October 28, 2022, Environmental Defence filed its evidence.

On November 1, 2022, Three Fires Group filed a letter requesting that Enbridge Gas provide answers to supplementary questions arising out of Enbridge Gas's responses to undertakings. In a letter dated November 4, 2022, Enbridge Gas submitted that it had provided sufficient information through the interrogatory process, the technical conference and the undertaking responses.

On November 2, 2022, Enbridge Gas requested a further extension to the procedural timeline for the process that the OEB established in Procedural Order No. 2.

On November 10, 2022, the OEB issued Procedural Order No. 3, accepting Enbridge Gas's extension request and revised the schedule for the remainder of the proceeding. The OEB also ordered that Enbridge Gas file responses to the supplementary questions from Three Fires Group and set a date for these responses.

In accordance with the updated schedule, written discovery on Environmental Defence's evidence and on Enbridge Gas's reply evidence was completed on November 28, 2022. Enbridge Gas's responses to supplementary questions by Three Fires Group were also filed on November 28, 2022.

On December 5, 2022, Enbridge Gas filed a letter advising the OEB that, due to unexpected circumstances, it was not in a position to file its argument-in-chief and requested that the OEB place the application in abeyance until updates to the evidence are available. Enbridge Gas stated that it received new cost information that may materially increase the estimated cost of the Project and therefore additional time is needed to update or amend the evidence.

Environmental Defence, FRPO and IGUA filed letters raising concerns about the economics of the Project and whether contributions in aid of construction (CIAC) from customers should be required. Pollution Probe filed a letter raising a concern on whether customers should be notified.

On December 14, 2022, the OEB issued Procedural Order No. 4, placing Enbridge Gas's application in abeyance as of December 5, 2022 and ordered Enbridge Gas to confirm the date it expects to file an amended application by February 1, 2023. Procedural Order No. 4, also directed that Enbridge Gas address the applicability of E.B.O. 134[13] and E.B.O. 188[14] in its amended application, and the extent to which CIAC payments should be required. The OEB also noted that Enbridge Gas may wish to consider whether it should communicate with potentially affected customers regarding the position of some parties that CIAC payments should be required.

On February 1, 2023, Enbridge Gas filed a letter informing the OEB that, based on actual 2022 attachments and on updated information on 2023 customer demand, the in-service date for the Project can be deferred to November 1, 2024. Enbridge Gas submitted that it expected to file evidence amendments no later than August 2023 and

[13] E.B.O. 134 Report of the Board: Review by the OEB of the Expansion of the Natural Gas System in Ontario, June 1, 1987, Amended on February 21, 2013, by Filing Guidelines on the Economic Tests for Transmission Pipeline Applications (EB-2012-0092)
[14] E.B.O. 188, January 30, 1998, Final Report of the Board, Appendix B: Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario

asked that the OEB continue to hold the application in abeyance until that time.

On February 7, 2023, the OEB issued Procedural Order No. 5, ordering that the application remain in abeyance and ordered Enbridge Gas to confirm the date it expects to file an amended application by July 31, 2023. Procedural Order No. 5 also set out a process for interim cost awards. On March 29, 2023, the OEB issued Decision and Order on Interim Cost Awards.

On June 16, 2023, Enbridge Gas filed its amended application which removed the Leamington Interconnect, and updated the project demand forecast, project construction and in-service schedules, the costs and economics and the other evidence affected by the changes in the project's scope, schedule and costs.

On July 28, 2023, the OEB issued an Amended Notice of Application and Procedural Order No. 6. Procedural Order No. 6 resumed processing the application and established a timeline for written interrogatories, a virtual technical conference, Enbridge Gas's argument-in-chief, written submissions by parties and a reply submission by Enbridge Gas.

On August 2, 2023 and August 15, 2023, SEC and Kitchener Utilities requested late intervention. On August 17, 2023, the OEB granted SEC and Kitchener Utilities intervenor status. The OEB also granted SEC cost award eligibility.

On August 25, 2023, the OEB issued a letter proposing an oral hearing, following the written discovery process, in place of the technical conference scheduled in Procedural Order No. 6 and proposed the scope for an oral hearing. In that letter, the OEB provided parties with an opportunity to file written submissions on the issues to be addressed in an oral hearing and the format any oral hearing might take and for a reply submission by Enbridge Gas.

APPrO, Atura Power, Energy Probe, IGUA and Pollution Probe filed written submissions on the scope and format of an oral hearing and Enbridge Gas filed a reply submission.

On September 21, 2023, the OEB issued Procedural Order No. 7, which scheduled a hybrid hearing (in person and virtual) following the written discovery process, in place of the previously planned technical conference and established a revised timeline for the remainder of the proceeding. The OEB also accepted Enbridge Gas's extension request to file responses to interrogatories on its amended application and updated responses to its previous interrogatory and undertaking responses to October 3, 2023 (from September 26, 2023).

On October 3, 2023, Enbridge Gas filed interrogatory responses regarding its amended application and also filed updated interrogatory and undertaking responses.

On October 12, 2023, Environmental Defence filed a letter proposing to update its evidence after reviewing Enbridge Gas's amended application and updated interrogatory responses and also requested direction on the need for Dr. McDiarmid's attendance at the oral hearing.

On October 13, 2023, the OEB set a date for Environmental Defence to file an update to its evidence and confirmed that Dr. McDiarmid's attendance at the oral hearing would be helpful. Environmental Defence filed its updated evidence on October 18, 2023.

On October 18, 2023, the OEB issued a letter, postponing the oral hearing for administrative reasons and cancelled the remaining steps set out in Procedural Order No. 7.

On October 30, 2023, the OEB issued Procedural Order No. 8 setting out new dates for the hybrid hearing and the remaining steps in the proceeding, including an additional procedural step for OGVG to file evidence concerning the greenhouse industry.

On November 3, 2023, Enbridge Gas filed updated reply evidence and updated interrogatory responses to its reply evidence to reflect Environmental Defence's updated evidence.

On November 6, 2023, OGVG filed its evidence.

The OEB held a three-day transcribed hybrid hearing from November 13-15, 2023.

On November 14, 2023, FRPO filed a letter asking that Enbridge Gas provide, as undertakings, simulation modeling related to hybrid alternatives filed in this proceeding. On November 20, 2023, Enbridge Gas filed a letter confirming that it would provide a response to FRPO's first request with its other undertaking responses but that it should not be required to respond to the second undertaking request. FRPO filed a reply letter on November 21, 2023.

On November 22, 2023, the OEB directed Enbridge Gas to file responses to both of FRPO's additional requests and an additional question from the OEB. The OEB requested that Enbridge Gas respond to the requests for additional information by November 30, 2023.

On November 22, 2023, Enbridge Gas, Environmental Defence and OGVG filed written responses to undertaking requests from the hybrid hearing.

On November 30, 2023, Enbridge Gas filed its argument-in-chief and responses to FRPO's and the OEB's additional requests.

Written submissions by OEB staff and intervenors are set to be due on December 14, 2023 and Enbridge Gas's written reply submission is due on January 18, 2024.

3 OEB Staff Submission

OEB staff supports approval of Enbridge Gas's leave to construct application, subject to the conditions of approval contained in Schedule A of this submission. OEB staff also supports the approval of the forms of agreement for permanent easement and temporary land use proposed by Enbridge Gas.

Consistent with the OEB's Standard Issues List for natural gas leave to construct applications, OEB staff's submission is structured to address the following issues:

1. Project Need
2. Project Alternatives
3. Project Cost and Economics
4. Environmental Impacts
5. Landowner Matters
6. Indigenous Consultation
7. Conditions of Approval

3.1 Project Need

OEB staff submits that the evidence supports the need for incremental capacity to be added to the Panhandle system. As discussed later in the section on alternatives, OEB staff is of the view that the Project is the best alternative to meet that need.

In the 2022/2023 winter, the existing capacity on the Panhandle system is 737 TJ/d. Enbridge Gas forecasted demand growth beginning in the winter of 2024/2025 and increasing annually to 921 TJ/d by the winter of 2030/2031.

Enbridge Gas noted that without an increase to the Panhandle system capacity, there will be shortfalls relative to the forecasted Design Day Demand. Enbridge Gas identified the first capacity shortfall of 66 TJ/d starting in the winter of 2024/2025. The shortfall is projected to grow to 156 TJ/d in the winter of 2028/2029 and to 184 TJ/d in the winter of 2030/2031. The Panhandle system capacity and Design Day Demand for the period 2019/2020 to 2030/2031 is set out in Table 1 below.[15]

[15] Exhibit B, Tab 2, Schedule 1, page 11, Table 3: Panhandle System Capacity, Design Day Demand and Shortfall, filed June 16, 2023

Table 1
Projected Demand Surplus/Shortfall (Status Quo)

	Historical Actuals			FORECAST								
	Winter 19/20	Winter 20/21	Winter 21/22	Winter 22/23	Winter 23/24	Winter 24/25	Winter 25/26	Winter 26/27	Winter 27/28	Winter 28/29	Winter 29/30	Winter 30/31
Panhandle System Capacity (TJ/d)	**725**	**725**	**713**	**737**	**737**	**737**	**737**	**737**	**737**	**737**	**737**	**737**
Design Day Demand Forecast (TJ/d)	**640**	**656**	**672**	**698**	**730**	**802**	**849**	**863**	**878**	**892**	**906**	**921**
Surplus (shortfall is negative) (TJ/d)	84	69	41	38	6	(66)	(112)	(127)	(141)	(156)	(170)	(184)

Enbridge Gas noted that if leave to construct the Project is granted, the incremental 168 TJ/d of capacity provided by the Project would be sufficient to address the forecasted demand growth through the winter of 2028/2029. The projected Design Day Demand surplus / shortfall in the scenario where leave to construct is granted below.[16]

Table 2
Projected Demand Surplus/Shortfall with Incremental Capacity Provided by the Project

	Historical Actuals (TJ/d)			Forecast (TJ/d)								
	Winter 19/20	Winter 20/21	Winter 21/22	Winter 22/23	Winter 23/24	Winter 24/25	Winter 25/26	Winter 26/27	Winter 27/28	Winter 28/29	Winter 29/30	Winter 30/31
Panhandle System Capacity (TJ/d)	**725.00**	**725.00**	**713.00**	**737.00**	**737.00**	**904.00**	**904.00**	**904.00**	**904.00**	**904.00**	**904.00**	**904.00**
Design Day Demand Forecast (TJ/d)	**640.00**	**656.00**	**672.00**	**698.00**	**730.00**	**802.00**	**849.00**	**863.00**	**878.00**	**892.00**	**906.00**	**921.00**
Surplus (negative is shortfall)	84.00	69.00	41.00	38.00	6.00	102.00	55.00	41.00	26.00	12.00	(2.00)	(17.00)

Under this scenario, assuming the Project is in-service for the winter of 2024/2025 and the forecasted demand materializes, the first shortfall of 2 TJ/d will occur in the winter of 2029/2030, increasing to 17 TJ/d in 2030/2031. Enbridge Gas noted that it will assess the capacity position on the Panhandle system each year and at such time, evaluate whether an Integrated Resource Planning (IRP) alternative could feasibly delay the need for further physical capacity beyond the winter of 2028/2029.[17]

Particulars of the Forecasted Demand that Underpins the Need for the Project

Of the total 168 TJ/d of capacity provided by the Project, incremental contract customer

[16] Enbridge Gas response to interrogatory I.STAFF.6, October 3, 2023 Table 1: Panhandle System Capacity (following reinforcement), Design Day Demand and Shortfall
[17] Enbridge Gas response to interrogatory I.STAFF.6 a), October 3, 2023

demand is forecast to take up 94% of the total capacity and general service customer incremental demand is projected to take up approximately 6% of the total capacity.

In the sub-sections that follow, OEB staff has summarized Enbridge Gas's evidence with respect to the forecasted general service and contract demand that supports the Project.

General Service Demand Forecast

The general service rate category includes residential, commercial, and small industrial customers. As of the winter of 2022/2023, approximately 44% of the firm demand served by the Panhandle system is for general service customers. Enbridge Gas forecasted that general service customer demand in the Panhandle area will increase by a total of approximately 4.6% between winter 2022/2023 and 2030/2031.[18] This forecast for general service demand growth was derived from Enbridge Gas's attachment forecast, which was converted into a volumetric forecast using average volumetric demand and considering the geographic location of the expected new attachments.

Enbridge Gas forecast that approximately 6% of the incremental 168 TJ/d of capacity provided by the Project would be used by general service customers.[19]

Enbridge Gas stated that the Project would ensure safe and reliable service by maintaining sufficient Panhandle system capacity to serve the growth of general service customers for, at least, four years.[20]

Contract Demand Forecast

The contract rate category includes, but is not limited to, large volume commercial, greenhouse and power generator customers.

In order to forecast demand in this category, Enbridge Gas administered, between February 23, 2023 and April 6, 2023, a non-binding Expression of Interest (2023 EOI) and Binding Reverse Open Season (ROS) process.

Enbridge Gas stated that it plans to execute distribution service contracts with customers who expressed interest for service commencing in 2024 and 2025 and

[18] Exhibit B, Tab 1, Schedule 1, page 10, paragraph 36
[19] Exhibit B, Tabb 1, Schedule 1, pages 10-11, paragraph 36
[20] Exhibit B, Tab 1, Schedule 1, page 11, paragraph 38

secure the remaining contracts from contract rate customers in the years to follow.[21]

In response to the 2023 EOI, Enbridge Gas received 42 expressions of interest with a firm contract demand of 131 TJ/d starting in 2024 and 2025.[22] Enbridge Gas indicated that it combined the 2023 EOI results with the previously contracted volumes from the 2021 EOI and the volumes contracted in the normal course of business to determine the total demand forecast of 197 TJ/d for the 2024 to 2033 period.[23] Of the 42 bids received from 39 entities by April 6, 2023, in the 2023 EOI, 38 were from the greenhouse sector, 2 from the electricity generation (power) sector and 2 from the commercial sector.[24]

Enbridge Gas's total forecast incremental firm demand, by year, on the Panhandle system of 197 TJ/d for the period 2024 to 2033 is shown in Table 3 below.

Table 3
Panhandle Region Expansion Project – EOI and Reverse Open Season[25] by Year

m3/hour	2023	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	
New /Incremental Interruptible (by year)		-	-	441	-	-	500	-	-	-	500	1,441
New /Incremental Interruptible (cumulative)		-	-	441	441	441	941	941	941	941	1,441	
Firm TJ/day (by year)		33	71	24	16	21	11	9	8	5	1	197
Firm TJ/day (cumulative)		33	104	127	143	164	175	183	191	196	197	

The demand from the 2023 EOI of 131 TJ/d represents approximately 78% of the

[21] Exhibit B, Tab 1, Schedule 1, page 7, paragraph 26, page 10, paragraph 33; Attachment 8: 2023 Expression of Interest Non-Binding Bid Form, Attachment 9: 2023 Distribution Service Binding Reverse Open Season Form; and Exhibit B, Tab 1, Schedule 1, pages 10-11, paragraphs 36-38, filed June 10, 2023
[22] Enbridge Gas response to interrogatory I.STAFF.24, a) Table 1: 2024 and 2025 Incremental Customer Demand Requirements (Underpinned by Firm Distribution Contract and In Negotiation) by Customer and Sector, filed June 10, 2023
[23] Exhibit B, Tab 1, Schedule 1, page 7, paragraph 26, filed June 10, 2023. Other volumes contracted after the 2021 EOI in the normal course of business are also included in the 197 TJ/d forecast.
[24] Exhibit B, Tab 1, Schedule 1, page 7, paragraph 27, filed June 10, 2023
[25] Enbridge Gas received no requests, through the ROS process, from existing customers seeking to de-contract existing firm or interruptible capacity.

demand for the incremental capacity created by the Project. OEB staff notes that, in addition to the demands by contract customers through bidding in 2023, Enbridge Gas has also been negotiating with additional potential contract customers who did not submit 2023 EOI bids and are prospective customers looking to locate in Windsor, Essex County, and Chatham-Kent. Enbridge Gas stated that it will likely acquire additional contract customers through these negotiations.

Enbridge Gas has already executed four distribution service contracts – one with a power generator and three with greenhouse sector customers. The contract with the power generator is a five-year contract for 57 TJ/d which reflects about 34% of the incremental capacity that would be created by the Project. The three contracts with the greenhouse sector customers are for a total of 4.6 TJ/d.[26] In total, these four executed contracts make up for 61.6 TJ/d (or 36.6%) of the incremental capacity that would be created by the Project.

Power Generation Sector Demand

The demand for incremental firm service by the power generation sector is a key driver for the Project.

On October 6, 2022, the Ontario Minister of Energy directed the IESO to procure 1,500 MW of natural gas fired generation capacity for 2025 to 2027 in-service dates.[27]

Enbridge Gas indicated that the Brighton Beach Generating Station doing business as Atura Power (Atura) executed a 10-year contract with the IESO for 42.4 MW efficiency upgrades to meet the local power generation needs between 2024 and 2028. Atura submitted a bid and executed a firm distribution contract agreement with Enbridge Gas for 57 TJ/d. Atura provided a letter of support for the Project and participated in the proceeding.[28] Enbridge Gas also advised that it is in the process of negotiating with the two other power generators for additional capacity starting in 2025.[29] These two generators submitted bids for service starting in 2025 for 6.3 TJ/d and 25.1 TJ/d respectively.[30] Combined incremental demand on the Panhandle system for the three generators noted above is 89 TJ/d, which represents about 53% of the total incremental capacity of 168 TJ/d created by the Project.

[26] Enbridge Gas response to Undertaking J2.12 by Pollution Probe, dated November 22, 2023
[27] Exhibit B, Tab 1, Schedule 1, page 17, paragraph 57
[28] Exhibit B, Tab 1, Schedule 1, Attachment 5
[29] Enbridge Gas response to interrogatory I.PP.32 a) and b)
[30] Enbridge Gas response to interrogatory I.STAFF.24 a) Table 1: 2024 and 2025 Incremental Customer Demand Requirements (Underpinned by Firm Distribution Contract and in Negotiation) by Customer by Sector

Greenhouse Sector Demand

The demand for incremental firm service on the Panhandle system by the greenhouse sector in the Windsor-Essex and Chatham-Kent area is another key driver of the need for the Project. 38 bids were received through the 2023 EOI and three contracts have been executed. Greenhouses use natural gas for space heating, electricity generation and carbon-dioxide production which is essential for plant growth. The total volume of bids by greenhouse sector for firm service contracts for 2024 and 2025 is approximately 42 TJ/d, representing approximately 25% of the total incremental capacity of 168 TJ/d created by the Project.[31]

OGVG, an intervenor in the proceeding, supported the Project. OGVG stated that greenhouse operations will continue to expand in the area served by the Panhandle system and indicated "…the need for new natural gas capacity in the next three years."[32]

Automotive Sector Executed Contract and Potential Demand

Enbridge Gas finalized a distribution service contract with NextStar Energy Inc. (NextStar) for distribution service in September 2023 using existing Panhandle system capacity. NextStar will operate a large-scale electric vehicle (EV) manufacturing facility. NextStar is a joint venture a joint-venture agreement between LG Energy Solution and Stellantis N.V.[33]

Enbridge Gas stated that after the NextStar EV battery plant was announced it received and responded to multiple confidential inquiries from other EV battery components manufacturers about natural gas service in the Windsor-Essex region. Enbridge Gas concluded that these inquiries indicate that there is potential for even higher demand for firm capacity by manufacturing companies that are seeking to locate in the Panhandle service area.[34]

OEB Staff Submission

OEB staff submits that there is a need for the incremental 168 TJ/d of capacity on the Panhandle system that is created by the Project. This is supported by Enbridge Gas's demand forecast as described in detail above. The Project addresses the forecast capacity shortfall on the Panhandle system until after the 2028/2029 winter.

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[31] Percentages calculated using the information that Enbridge Gas provided in response to interrogatory I.STAFF.24 a) Table 1.
[32] Hybrid Hearing Transcript, November 13, 2023, page 33, lines 16-19
[33] Exhibit B, Tab 1, Schedule 1, page 5, paragraph 18, filed June 10, 2023
[34] Exhibit B, Tab 1, Schedule 1, page 20, paragraph 65

OEB staff notes that of the total 168 TJ/d of capacity provided by the Project, incremental contract customer demand is forecast to take up 94% of the total capacity and general service customer incremental demand is projected to take up only approximately 6% of the total capacity. Therefore, it is clear that contract customer demand is the key driver underpinning the need for the Project. OEB staff further notes that over the next decade, the ratio of contract customers' use of the Panhandle system will steadily increase relative to general service customers.[35]

For the purposes of evaluating the need for the Project, it is important to consider the specific categories of contract customers that are seeking capacity on the Panhandle system. Power generators take up more than half of the incremental capacity. The combined demand of 89 TJ/d of the three natural gas fired generators represents approximately 53% of the total incremental capacity of 168 TJ/d created by the Project. OEB staff notes that the IESO is seeking to procure significant amounts of new gas-fired generation capacity, which provides support that this forecast demand will be actualized subject only to the power generators' decisions regarding their projects in the context of potential requirements for CIAC payments in the scenario that the OEB determines that is appropriate.

OEB staff notes that the greenhouse sector is another major driver of the need for the Project. The total volume of bids by the greenhouse sector for firm capacity in 2024 and 2025 is approximately 42 TJ/d, representing about 25% of the total incremental capacity provided by the Project. OEB staff submits that, as is discussed in more detail in the alternatives section, greenhouses do not have viable economic alternatives to natural gas service. Therefore, this demand will also likely be actualized subject only to the greenhouse growers' decisions regarding their planned expansions in Ontario in the context of potential requirements for CIAC payments to be made in the scenario that the OEB determines that is appropriate.

Similarly, OEB staff notes that the growing automotive sector is another potential contract customer category that will likely seek incremental firm capacity on the Panhandle system.

Overall, OEB staff is the view that there is a need for the Project that is well supported by the demand forecast. As discussed later in this submission, the Project is the best alternative to meet the forecast incremental demand that underpins the needs for the Project (i.e., largely, power generators and greenhouse growers). However, this need is predicated on the assumption that no CIACs would be required for the Project. If the

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[35] Enbridge Gas response to interrogatory I.APPrO.6 c) and d) updated October 3, 2023.
In 2022/2023, the ratio of contract to general service demand on the Panhandle system was 56:44. By the winter of 2033/2034, the ratio of contract to general service demand on the Panhandle system is expected to be 66:34.

OEB determines that CIACs are required, Enbridge Gas would need to go back to the contract customers that have expressed interest, or have signed contracts, for the incremental demand created by the Project to reaffirm their requirements and determine whether the expected demand remains.

3.2 Project Alternatives

Proposed Project – Preferred Alternative

Enbridge Gas stated that the Project is the best alternative to provide 168 TJ/d incremental capacity to meet the needs from November 1, 2024 to the winter of 2028/2029. Enbridge Gas noted that the Project has the lowest cost per unit capacity.

Enbridge Gas noted that the Project addresses the pressure bottleneck between Dover Transmission Station and Comber Transmission Station. Enbridge Gas also stated that the location of the tie-in facilities at Richardson Sideroad near the existing roads reduces the potential environmental impacts.

Enbridge Gas's assessment of alternatives involved identification of potential alternatives that could address the forecasted incremental demand including facility alternatives, IRP alternatives and hybrid alternatives (supply side IRP alternatives combined with facility).

Enbridge Gas assessed the viability of these alternatives using the following criteria[36]:

- Capacity provided relative to the forecast demand
- Cost Effectiveness - total cost, cost per unit of capacity, net present value
- Timing – an in-service date of November 1, 2024 is required, five-year forecast firm demand
- Safety and Reliability – qualitative assessment
- Risk Management – qualitative indicators such as price increase risk and availability
- Environmental and Socio-Economic Impacts - qualitative assessment of impacts on Indigenous peoples, landowners, municipalities, and environment

Alternatives Enbridge Gas Considered Viable

Enbridge Gas focused its comparative assessment on alternatives that it assessed as potentially viable.[37] Two pipelines facility alternatives and two hybrid alternatives were

[36] Exhibit C, Tab 1, Schedule 1, pages 3-4, updated
[37] Exhibit I.STAFF.7, Attachment 1, Comparison of Viable Alternatives – Facility and Hybrid, updated

subject to in-depth evaluation in order to select the preferred alternative.

Viable Facility Alternatives

Enbridge Gas considered paralleling the existing NPS 20 pipeline with two different size pipelines - NPS 30 or NPS 36.

Enbridge Gas determined that either a NPS 30 or NPS 36 pipeline to Richardson Sideroad would be sufficient to meet the five-year growth forecast. However, Enbridge Gas selected the NPS 36 pipeline as the preferred alternative. Enbridge Gas stated that although the NPS 30 alternative has lower capital costs, the NPS 36 option is more cost effective when maintenance costs are also considered as the NPS 36 option avoids costs associated with multiple pipeline inspection programs. Table 4 sets out Enbridge Gas's comparison of the incremental capacity and cost effectiveness of a NPS 30 pipeline relative to a NPS 36 pipeline, which highlights the anticipated advantages of the proposed Project.[38]

Table 4
Panhandle Loop – Economic Assessment

Potential Alternative	Incremental Capacity (TJ/d)	Costs ($ Million)	Net Present Value (1) ($ Million)	Cost per Unit of Capacity ($/TJ/d)
Facility Alternative: Looping of NPS 20 Panhandle				
Proposed Project 19 km Loop with NPS 36	168	$358.0	$(153.5)	$2.13
19 km Loop with NPS 30	160	$342.7 (2)	$(144.6)	$2.14

1. The calculation of the Net Present value does not include overheads
2. The estimated cost of $342.7 million for an NPS 30 alternative is based on a November 1, 2024 in-service date, for the purpose of displaying a direct comparative to the proposed Project. The actual installation of an NPS 30 alternative would result in a November 1, 2025 in-service date and as such the estimated cost would be higher due to inflationary impacts.

Viable Hybrid (supply side with facility expansion) Alternatives

Enbridge Gas stated that there are two potentially viable hybrid alternatives that would involve the available supply at Ojibway and construction of a pipeline to add to the

[38] Exhibit C, Tab 1, Schedule 1, pages 7-9, updated

system capacity.

The first hybrid alternative includes a 21 TJ/d firm exchange between Dawn and Ojibway beginning November 1, 2024, for a 40-year term coupled with an 18 km NPS 36 pipeline (instead of 19 km). Enbridge Gas stated that the 18 km NPS 36 pipeline would result in an endpoint located in the middle of a landowner's agricultural property, which is not a preferred location.

The second hybrid alternative includes a 21 TJ/d firm exchange between Dawn and Ojibway beginning November 1, 2024, for a 40-year term coupled with a 16.2 km NPS 36 pipeline ending at Wheatley Road. Enbridge Gas noted that this alternative does not provide enough capacity to serve the 5-year demand forecast.

Enbridge Gas determined that both options are not economic relative to the proposed Project, as shown in Table 5 below, and also contain a renewal risk associated with the firm exchange component.

Table 5
Hybrid Alternative Economic Assessment

Potential Alternative	Incremental Capacity (TJ/d)	Costs ($ Million)	NPV ($ Million)	Cost per Unit of Capacity ($/TJ/d)
17.86 km NPS 36 and 21 TJ/d Ojibway to Dawn Exchange	168	*Facility:* $351.0 *O&M:* $4.2 Annually $(66.2) over a 40-year term	$(212.1)	$2.48
16.20 km (i.e., Wheatley Road end-point) NPS 36 and 21 TJ/d Ojibway to Dawn Exchange	153	*Facility:* $330.5 *O&M:* $4.2 Annually $(66.2) over a 40-year term	$(204.0)	$2.59

1. The estimated O&M costs are based on the bid received in the Request for Proposal (RFP). The bid stated pricing is subject to refresh based on the market conditions at the timing of contracting.

Non-Viable Alternatives

Non-Viable Facility Alternatives

Enbridge Gas dismissed from further consideration the following three non-viable facility alternatives: [39]

- Replace and upsize the existing NPS 16 Panhandle Line west of the Dover Transmission Station
- Replace and upsize the existing NPS 20 Panhandle Line west of the Dover Transmission Station
- New LNG facilities

Replace and upsize:(i) the existing NPS 16 Panhandle Line west of the Dover Transmission Station; or (ii) the existing NPS 20 Panhandle Line west of the Dover Transmission Station[40]

These alternatives would require a replacement of the existing NPS 16 or NPS 20 pipeline with a larger diameter pipeline to provide the additional capacity needed. This approach would take the existing pipelines out of service for a period of time and potentially affect the reliability of service to existing customers. Enbridge Gas further noted that:

i) Upsizing the existing NPS 16 pipeline was not selected as it would require moving as many as nine downstream system connections from the NPS 16 line to the NPS 20 line and constructing a new interconnecting pipeline between the NPS 16 and NPS 20 lines. In addition, this alternative was not selected because it results in increased environmental, and landowner impacts and would not directly address the Panhandle system pressure bottleneck on the NPS 20 Panhandle Line between the Dover and Comber Transmission Stations.

ii) Upsizing the existing NPS 20 pipeline was not selected as the existing NPS 20 Panhandle Line is required to serve customers at all times of the year as the existing NPS 16 Panhandle Line cannot serve system demands on its own. As a result, reliable service to customers could not be maintained while the NPS 20 line is out of service.

LNG Facilities[41]

Enbridge Gas also considered constructing an above-ground LNG storage facility along the Panhandle system. The estimated cost to construct the LNG storage and related facilities is $287 million (approximately $390 million in today's dollars) with about $5 million in annual operating expenses. This alternative would result in 106 TJ/d of added capacity, which would be insufficient to support the system growth starting in the winter

[39] Exhibit I.STAFF.7, Attachment 2, Comparison of Non-Viable Alternatives – Facility and IRPA, updated
[40] Exhibit C, Tab 1, Schedule 1, pages 5-7, updated
[41] Exhibit C, Tab 1, Schedule 1, pages 9-10, updated

of 25/26. Enbridge Gas determined that this alternative was non-viable as it was expected to require more significant investment in both capital and annual operating expenses relative to the preferred option.[42]

Non-Viable Non-Facility Alternatives

Enbridge Gas assessed as non-viable the following two categories of non-facility, alternatives: (i) Supply-side Alternatives and (ii) Demand-side IRP alternatives:[43]

- Supply-side alternatives: Firm third-party exchange between Dawn and Ojibway and trucked compressed natural gas (CNG)
- Demand-side alternatives: interruptible rates, electrification/alternative energy sources and enhanced targeted energy efficiency (ETEE)

Supply-side Alternatives

Enbridge Gas determined that the supply-side third-party exchanges between Dawn and Ojibway and the trucked CNG alternatives are not viable and eliminated them from further assessment.

With respect to third-party exchanges between Dawn and Ojibway, Enbridge Gas noted that Ojibway supply serves the Windsor market, which is nearby to the Ojibway delivery point. However, this supply source is not available to serve markets on the Panhandle system. Enbridge Gas further explained that of the total 108 TJ/d of capacity operationally available to be delivered to Ojibway annually, 60 TJ/d is already used by Enbridge Gas to serve firm Design Day Demand. Additionally, Rover, a transmission operator that provides service to other shippers, contracted, until October 31, 2026 (with evergreen renewal rights), 37 TJ/d of the remaining 48 TJ/d capacity, which leaves 18 TJ/d to 21 TJ/d to be incrementally available to be delivered to the Panhandle system. Enbridge Gas submitted that this capacity is insufficient to meet the forecast demand shortfall. Therefore, Enbridge Gas determined that the Ojibway alternative as non-viable.[44]

The second supply side option that Enbridge Gas considered and eliminated as a non-viable was trucking CNG to supply natural gas to Panhandle system customers. This alternative was dismissed based on the complex logistics, the requirement to construct

[42] Exhibit C, Tab 1, Schedule 1, pages 13-14, paragraphs 38-39 and Enbridge Gas Argument-in-Chief, November 30, 2023, pages 20-21, paragraph 53
[43] Exhibit I.STAFF.7, Attachment 2, Comparison of Non-Viable Alternatives – Facility and IRPA, updated
[44] Exhibit C, Tab 1, Schedule 1, pages 15-16, paragraphs 44-45 and Enbridge Gas Argument-in-Chief, November 30, 2023, pages 22-23, paragraphs 57-61

infrastructure facilities, and security of supply risks.[45]

Demand-side Alternatives

In the sub-sections below, OEB staff summarizes the three demand-side alternatives considered by Enbridge Gas (ETEE, interruptible rates and electrification/alternative energy sources). OEB staff notes that ETEE was considered by Enbridge Gas as an IRP alternative. Interruptible rates and electrification/alternative energy source options were taken into account by Enbridge Gas through adjustments to the demand forecast underpinning the Project need.

Enhanced targeted energy efficiency

On behalf of Enbridge Gas, Posterity Group (Posterity) conducted an assessment of the potential peak demand reduction that could be provided by ETEE as an IRP alternative (i.e., reducing peak demand in the area served by the Project by increasing uptake of energy efficiency measures, through the use of higher customer incentives or enhanced marketing, relative to the baseline of energy efficiency programming offered through Enbridge Gas's existing demand-side management programs). This assessment was originally done only for the Leamington area, but a second assessment was later conducted by Posterity that included a larger geographic area served by the Panhandle system (Windsor and Chatham areas, in addition to Leamington), providing a larger customer base for peak demand reductions.

Posterity's assessment concluded that a maximum peak hour reduction potential of approximately 72,000 m^3/hour (57 TJ/day) from general service customers could be obtained by the winter of 2029/2030. Based on Posterity's assessment, Enbridge Gas concluded that ETEE is not technically viable, as it cannot meet the full capacity required by the Project. During the hearing, Enbridge Gas also indicated that the possible savings from ETEE could not address the need for the Project, even if combined with other alternatives, such as supply-side alternatives, due to timing issues. Enbridge Gas noted that the 57 TJ/day of potential savings from ETEE is an estimate of what could be achieved by the winter of 2029/2030 (assuming multiple prior years of ETEE program activity), yet there is a 66 TJ/day deficit on the Panhandle system as soon as the winter of 2024/2025.[46]

Enbridge Gas also submitted that ETEE had a higher cost per unit of capacity relative to the Project ($8.2 million/TJ/day vs $2.14 million/TJ/day). However, this cost comparison is based only on the cost to Enbridge Gas, not the full 3-phase test (Discounted Cash

[45] Exhibit C, Tab 1, Schedule 1, page 23, paragraphs 68-69
[46] Oral Hearing Transcripts, Vol. 3, pages 81-82.

Flow-Plus (DCF+) test) used to compare costs and benefits of technically viable alternatives under the IRP Framework, and thus does not account for any commodity cost savings that participating customers realize from ETEE.[47]

Posterity's analysis of the potential of ETEE was limited to general service customers. Enbridge Gas expressed the view that ETEE opportunities for contract customers, including greenhouses, are limited, and these customers will already be making full use of Enbridge Gas's existing demand-side management (DSM) programs.[48] Enbridge Gas also indicated that the results of existing DSM activities would be captured within customer bids. Enbridge Gas's updated 2023 EOI asked customers seeking incremental capacity to confirm that their 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 DSM programs. Enbridge Gas also noted that energy efficiency that is realized in the contract market does not always result in a reduction in customer contract demand, as peak hour efficiencies can be used by the customer to expand operations and increase production.

In an undertaking response,[49] Enbridge Gas performed a rough extrapolation of Posterity's results to the contract sector (excluding power generators), and estimated a peak hour reduction potential for contract customers from ETEE of 21 TJ/day by 2029. However, Enbridge Gas cautioned against the use of this result for the reasons discussed above.

OGVG's witness, Dr. Petro, confirmed that greenhouse customers are participating in Enbridge Gas's DSM programs, but was not able to comment as to whether there was anything more Enbridge Gas could or should be doing to further improve its energy efficiency programs for the greenhouse sector.[50]

Interruptible Rates

Demand from customers on interruptible rates is not included by Enbridge Gas in its Design Day Demand forecast, as Enbridge Gas can curtail these customers if needed. For this reason, the IRP Framework indicates that Enbridge Gas should consider the impact of interruptible rates to meet system needs.[51] Enbridge Gas has the flexibility to propose modifying its interruptible rates within the area served by the Project as part of

[47] Oral Hearing Transcripts, Vol. 2, pages 149-150
[48] Exhibit I.Staff.10. See also TC Tr 2, pages66-70; Hearing Tr 2, pages 139-145
[49] Exhibit J2.10
[50] Oral Hearing Transcripts, Vol. 3, pages 174-176
[51] EB-2020-0091, Decision and Order, July 22, 2021, page 6

an IRP Plan, in order to increase customer adoption.[52]

In its original application, Enbridge Gas noted that it provided existing contract rate and large volume general service customers the opportunity to turnback firm or interruptible capacity or convert existing firm capacity to interruptible capacity in the Area of Benefit, including the use of a ROS. Enbridge Gas received no requests to turn back capacity as part of the Binding ROS.

In its updated EOI/ROS process in February 2023, customers were asked 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 who submitted 2023 EOI bids for new/incremental firm service were asked to provide information regarding the viability of interruptible service as an alternative to new firm service. Of the 42 EOI bids received, only 2 bids indicated that interruptible service was a viable alternative and that they could rely on alternate fuel sources during an interruption event. For those two bids, interruptible service was not requested, nor was there an accompanying ROS request to convert existing firm service to interruptible service. The firm demands from these two bids were not included in the updated demand forecast Enbridge Gas filed in support of its updated application.

Customers were also invited to indicate 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. 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 rates. Enbridge Gas indicated that it will work with these five customers to determine if their future natural gas requirements can be met with interruptible service despite their bid for new/incremental firm service. The firm demands from these five bids were not included in the updated demand forecast.

Alternative Energy Sources (including Electrification)

Electrification of space heating or other end uses (for contract customers in the greenhouse sector or for general service customers) could also reduce natural gas peak demand and the forecast shortfall on the Panhandle system. Enbridge Gas did not explicitly consider providing funding for electrification as an IRP alternative (for the

[52] EB-2022-0200, Decision on Settlement Proposal, August 17, 2023, Exhibit O1, Tab 1, Schedule 1, page 50 of 62

greenhouse sector or for general service customers), as it indicated that this is not permitted under the IRP Framework.[53]

Enbridge Gas's demand forecast for the Panhandle service area includes a small amount of fuel switching away from natural gas (likely switching to electricity) for general service customers in the coming years, using the same energy transition assumptions that Enbridge Gas applied to its demand forecast on a system-wide basis in its current rebasing proceeding.[54]

Enbridge Gas's demand forecast did not assume any electrification of greenhouse customers. Enbridge Gas indicated that it does not believe that there is an economically feasible alternative to natural gas for the greenhouse sector.

Evidence was also filed on behalf of ED and OGVG, by Dr. McDiarmid and Dr. Petro, respectively, that discussed the potential for greenhouse customers to switch to electric heat pumps (including geothermal systems) or other non-gas systems for some or all of their space heating needs. Dr. McDiarmid indicated that technically viable alternatives to natural gas exist for greenhouses.[55] However, Dr. McDiarmid indicated that this conclusion does not consider economic feasibility, and that she was not aware of any commercial greenhouse operations in Ontario using electric heat pumps.[56] Dr. Petro also indicated that he was not aware of any commercial greenhouse operations in Ontario using electric heat pumps as their primary source of heating. Dr. Petro further indicated that the use of natural gas as the heating source offered greenhouse producers a significant economic advantage by also providing the carbon dioxide used by growers as an input to crop production.[57] Carbon dioxide is a critical production input which otherwise would need to be separately purchased and is subject to significant pricing volatility. Dr. Petro also indicated that several other factors (i.e., limits on the maximum size of commercially available heat pumps, large land requirements for geothermal systems, and constraints on electricity supply to the area) also contributed to making use of heat pumps infeasible for commercial greenhouses in the Panhandle service area.[58]

Dr. Petro also discussed the use of biomass, indicating that it had value as a secondary heating fuel when available, but could not provide the level of reliability and security of supply that greenhouses require to ensure that they can meet their heating needs at all

[53] Oral Hearing Transcripts, Vol. 3, page 71
[54] These assumptions are described in: EB-2022-0200, Exhibit 1, Tab 10, Schedule 4, page 6
[55] McDiarmid Climate Consulting, Evidence regarding stage 2 analysis and gas alternatives for Greenhouses, Updated October 18, 2023, pages 6-7.
[56] Oral Hearing Transcripts, Vol. 1, pages 95-96
[57] Ontario Greenhouse Vegetable Growers, Evidence of Dr. Petro, November 6, 2023, pages 2-3
[58] Oral Hearing Transcripts, Vol. 3, pages 172-174

times and do not risk crop failure.[59]

OEB Staff Submission

OEB staff submits that the Project is the best alternative to meet the forecasted demand growth on the Panhandle system starting on November 1, 2024 until the winter of 2028/2029.

OEB staff’s conclusions regarding the facility, hybrid supply-side and demand-side alternatives are provided in the sub-sections below. OEB staff notes that its conclusions reflect the assumption that forecast demand from the contract sector for firm service will not change significantly from the forecast. However, this need is predicated on the assumption that no CIAC payments are required from the contract customers that are underpinning the need for the Project.[60] If the OEB determines that CIAC payments are appropriate, some of the contract customers may re-evaluate their plans and no longer require incremental natural gas service. Under that scenario, it may be appropriate for Enbridge Gas to revisit the possible role of alternatives to avoid the Project if the projected capacity shortfall is significantly reduced from the current forecast.

Facility Alternatives

As previously noted, OEB staff is of the view that the Project is the best alternative to meet the forecasted demand on the Panhandle system until the winter of 2028/2029.

OEB staff notes that another facility alternative that was considered viable by Enbridge Gas is the pipeline project along the same route but using NPS 30 diameter pipeline (instead of NPS 36 diameter pipeline). This alternative would create an estimated 8 TJ/d less capacity than the Project, has a marginally lower total cost of $342.7 million and a higher cost per unit capacity (i.e., $2.14 TJ/d (alternative) vs $2.13 TJ/d (proposed Project)). OEB staff submits that this alternative, although viable and less costly on a total cost basis, is not a preferred option as it does not create the incremental capacity required to meet the need in the winter of 2028/2029 and is at a slightly higher unit cost per TJ/d.[61]

OEB staff also agrees with Enbridge Gas’s determination to eliminate the two other pipeline facilities alternatives as non-viable (i.e., replacement and upsizing of the existing NPS 16 or replacement and upsizing of the existing NPS 20 Panhandle pipeline west of Dover). Enbridge Gas considered and dismissed these two options early in the

[59] Oral Hearing Transcripts, Vol. 3, page 133
[60] OEB staff’s position on the appropriate economic test to be applied to the Project (including the requirement for CIACs) is discussed in detail in the Project Economics sub-section of the submission.
[61] Enbridge Gas response to interrogatory I.STAFF.7, Attachment 1, updated

alternatives evaluation process because the construction cannot be completed for November 1, 2024, and cannot maintain reliable service to the existing Panhandle customers.[62]

Finally, OEB staff submits that construction of a new LNG storage facility is not a viable facility alternative as: (a) the cost is higher than the Project; (b) it does not create sufficient capacity; and (c) it cannot be constructed in time to be in-service for the winter of 2024/2025.

Hybrid Alternatives

OEB staff submits that Enbridge Gas's assessment of the hybrid alternatives is reasonable. The hybrid alternatives considered and dismissed by Enbridge Gas are not optimal to address the need for the incremental capacity between the winters of 2024/2025 and 2028/2029.

Enbridge Gas stated that the two hybrid options of building approximately either 16 km or 18 km of the NPS 36 pipeline combined with 21 TJ/d firm exchange between Dawn and Ojibway are not preferred options. OEB staff submits that the option of building 18 km NPS 36 pipeline with added 21 TJ/d capacity from Ojibway would create sufficient capacity but at the higher cost per unit of capacity (i.e. $2.48/TJ/d (alternative) vs. $2.13/TJ/d (proposed Project)). In addition, this hybrid alternative has future price risk for the contracted exchange services between Dawn and Ojibway as well as contractual risk of not having sufficient volumes available at Ojibway. With respect to the hybrid option to build a 16.2 km pipeline combined with an added 21 TJ/d supply at Ojibway, OEB staff submits that this alternative has all of the shortcomings of the first hybrid option and would not provide sufficient capacity for the established need.[63]

Supply-side Alternatives

OEB staff submits that firm third-party exchanges between Dawn and Ojibway or trucking CNG are not viable alternatives to address the need for incremental capacity on the Panhandle system for the 2024/2025 to 2028/2029 period.

OEB staff submits that Enbridge Gas demonstrated that the 21 TJ/d of available capacity at Ojibway is not sufficient to address the need. Enbridge Gas supported this assertion by issuing a formal RFP for a Firm and Obligated Call Option Exchange Service beginning between November 1, 2023, and November 1, 2024, and until 2026. Enbridge Gas also approached the existing shipper Rover to express interest in the RFP. No interest was received from Rover. Only one market participant responded to

[62] Enbridge Gas response to interrogatory I.STAFF.7, Attachment 2, updated
[63] Enbridge Gas response to interrogatory I.STAFF.7, Attachment 1, updated

the RFP for 19 TJ/d out of 21 TJ/d delivery capacity available at Ojibway.[64] Based on the evidence provided by Enbridge Gas, OEB staff submits that a firm exchange between Dawn and Ojibway is not commercially available and cannot defer the incremental capacity need starting in the winter of 2024/2025.

OEB staff further submits that trucking CNG is not a viable alternative because of the complexity of delivering more than 400 truckloads per day and the requirement for additional infrastructure construction.

<u>Demand-side Alternatives</u>

OEB staff submits that Enbridge Gas has demonstrated that no demand-side alternative, alone or in combination with supply-side alternatives, can meet the identified need that would be addressed by the Project.

The forecast shortfall (156 TJ/day by winter of 2028/2029) on the system that will be addressed by the Project is 22% of current demand on the system (698 TJ/day in winter of 2022/2023) and more than 50% of the current demand from general service customers (306 TJ/day).[65] OEB staff submits that the magnitude of the forecast near-term shortfall means that addressing this shortfall through demand-side alternatives is not achievable.

Additional rationale is provided below on each of the three demand-side alternatives for any potential subsequent expansion of the Panhandle system.

*<u>Interruptible Rates</u>**<u>:</u>** OEB staff submits that Enbridge Gas has adequately considered interruptible rates by gauging customer interest through the EOI and adjusting its demand forecast by removing all demand associated with bids in the EOI from customers that showed any interest in interruptible rates. There is no evidence to suggest that the actual demand reduction from interruptible rates would likely be greater than the adjustment Enbridge Gas has made to its forecast.

<u>Electrification:</u> OEB staff agrees with Enbridge Gas that Enbridge Gas is not required to consider funding electrification alternatives under the IRP Framework, as the OEB has determined that "as part of this first-generation IRP Framework, it is not appropriate to provide funding to Enbridge Gas for electricity IRPAs."[66] However, Enbridge Gas is required to consider how customer-driven electrification may impact natural gas demand in assessing project need. For general service customers, as reflected in OEB staff's submission in Enbridge Gas's rebasing proceeding, OEB staff believes that

[64] Argument-in-Chief, November 30, 2023, pages 23-24, paragraphs 60-63
[65] Exhibit B, Tab 2, Schedule 1, page 11, Tables 2 and 3
[66] EB-2020-0091, Decision and Order, July 22, 2021, page 35

Enbridge Gas's energy transition forecasting assumptions likely underestimate the pace of electrification among general service customers.[67] However, OEB staff does not believe that customer-driven electrification will reduce natural gas demand by the amount that would be required to avoid the Project.

For the greenhouse sector, based on the evidence provided by Dr. McDiarmid and Dr. Petro, there are significant challenges regarding the technical viability and economic feasibility of using ground source (geothermal) or air source heat pumps for greenhouses. Importantly, there is no evidence that these technologies are currently being used in any commercial greenhouse operation in Ontario. There are also challenges with expanding the use of biomass as a fuel source. OEB staff does not believe that electrification of the greenhouse sector, or more extensive use of biomass, is likely to significantly reduce the sector's demand for natural gas, at least in the near term.

In addition, as noted in the need section, more than 50% of the incremental capacity created by the Project is expected to serve natural gas-fired power generators, which do not have viable economic options except for service from Enbridge Gas.

Enhanced Targeted Energy Efficiency: OEB staff agrees with Enbridge Gas that the large amount of demand reduction that would be required to avoid the Project, including the significant amount of demand reduction that would be required as soon as the winter of 2024/2025, means that ETEE is not a technically viable alternative to address the need.

However, Enbridge Gas has already signaled the potential need for another phase of expansion to meet future growth in the Panhandle service area.[68] Enbridge Gas indicated it will consider IRP alternatives to reduce, avoid or defer the potential second phase of transmission expansion.[69] OEB staff has concerns with the approach described by Enbridge Gas at the oral hearing.[70] First, OEB staff questions Enbridge Gas statements that its initial assessment of IRP alternatives had not found any technically viable alternatives for this second phase, even though the forecast level of incremental growth, at least at this time, is lower than in the first phase, being 14 TJ/day in each of 2028/2029 and 2029/2030.[71] Second, OEB staff takes issue with Enbridge Gas's statement that it would not make a determination on the best option until closer to the required in-service date when the need has been confirmed. It is likely that this approach would lead to the potential role of ETEE (for general service or contract

[67] EB-2022-0200, OEB Staff Submission (Phase 1), September 12, 2023, page 38
[68] Exhibit B, Tab 1, Schedule 1, page 22
[69] Exhibit I.Staff.10
[70] See cross-examination by OGVG at Oral Hearing Transcripts, Vol. 3, pp. 146-152
[71] Exhibit B, Tab 1, Schedule 1, Table 1, page 13

customers) as an IRP alternative again being rejected due to the longer lead time needed for ETEE to deliver results. OEB staff submits that this wait and see approach is inconsistent with the intent of the IRP Framework to identify potential system needs/constraints well in advance to ensure adequate lead time for a detailed consideration of alternatives.[72]

OEB staff also submits that the potential role of ETEE for contract customers should be given more consideration by Enbridge Gas in this potential future phase.

To address these concerns, OEB staff submits that the OEB should direct Enbridge Gas to assess whether it recommends a proactive IRP Plan, including the use of ETEE, to avoid or reduce the scope of future transmission expansion of the Panhandle system. This assessment should be filed as part of a future Enbridge Gas annual IRP report (which already requires Enbridge Gas to report more generally on the results of its IRP Assessment Process). Enbridge Gas should consider the trade-offs as to the appropriate time to act to address an identified system need (e.g., delay allows system need to be specified with more certainty but may rule out IRP alternatives). OEB staff notes that the issue of ETEE requiring more lead time to deliver demand reduction is not unique to the Panhandle service area, so it may be appropriate for Enbridge Gas to describe how it will address this issue as part of its approach to IRP assessment more generally, and then show how this impacts Enbridge Gas's conclusions for its IRP assessment of the second phase of expansion of the Panhandle system.

In addition, OEB staff submits that for all new or existing contract customers entering into natural gas contracts for additional firm capacity on the Panhandle system, Enbridge Gas should be required to proactively engage these customers to identify potential energy efficiency opportunities. This could include an on-site audit or assessment of any existing operations, an analysis of any energy efficiency opportunities in planned new operations, and identification of any Enbridge Gas programs that may support investments in energy efficiency measures.

3.3 Project Cost and Economics

Project Costs

OEB staff notes that construction of the Project is divided into two phases. The first phase, which is to start construction in Q1 of 2024, involves: (i) construction of the Panhandle Loop; (ii) modifications to the Panhandle Take-Off Station and Dover Transmission Station; and (iii) construction of the new Richardson Valve Site Station. The second phase, which is to start construction in Q2 of 2025, involves upgrades to

[72] EB-2020-0091, Decision and Order, July 22, 2021, page 4

the Dawn Yard.

Capital Cost Estimates

The current estimated cost of the Project is $358.0 million.[73] In its evidence, Enbridge Gas provided the Project costs by category as set out in Table 6 below.

Table 6
Project Costs

Item No.	Cost Description	NPS 36 Mainline	NPS 36 Stations	NPS 36 Subtotal	Dawn	Total
1	Materials	$ 28.3	$ 2.2	$ 30.5	$ 26.4	$ 57.0
2	Labour	2.7	0.2	2.8	0.9	3.8
3	External Permitting and Land	17.4	-	17.4	-	17.4
4	Outside Services	130.8	5.4	136.2	42.0	178.1
5	Contingency	13.9	0.6	14.5	6.3	20.8
6	Interest During Construction	6.4	0.3	6.7	5.4	12.1
7	Total Direct Capital Cost	199.5	8.6	208.1	81.1	289.2
8	Indirect Overheads	48.0	2.1	50.1	18.7	68.8
9	Total Project Cost	$ 247.5	$ 10.7	$ 258.2	$ 99.8	$ 358.0

Enbridge Gas noted that the Project costs are based upon a class 3 estimate prepared in Q1 2023, updated to reflect market conditions based on Q4 2022 contractor responses to a RFP.[74]

Enbridge Gas compared the cost estimate for the Project with the cost estimate for the Dawn to Corunna project, which was recently approved by the OEB.[75] Construction of the Dawn to Corunna project started in June 2023. Enbridge Gas notified the OEB on November 21, 2023, that the Dawn to Corunna project was to be in-service by November 30, 2023.[76] Although the construction has been completed, the actual final cost of the Dawn to Corunna project have not been reported to the OEB at this time. The estimated Project costs compared against the most recent forecast costs for the Dawn to Corunna project are set out in Table 7 below.

[73] Exhibit E, Tab1, Schedule 1, page 1, and Schedule 2: Panhandle Regional Expansion Project Cost
[74] Exhibit E, Tab 1, Schedule 1, page 1, paragraph 2
[75] Exhibit E, Tab 1, Schedule 1, page 2, Table 1: Project Cost Comparison – Pipeline Costs
[76] Enbridge Gas Inc. Letter to the OEB, In-service date of the Dawn to Corunna Project (EB-2022-0086), November 21, 2023

Table 7
Project Cost Comparison

Item No.	Description	(a) **Proposed Project** Panhandle Loop (EB-2022-0157)	(b) **Current Forecast** Dawn to Corunna (EB-2022-0086)	(c) = (a)-(b) **Variance**
	Pipeline Diameter	***NPS 36***	***NPS 36***	
	Length	***19 km***	***20 km***	
	Pipeline Material	***Steel***	***Steel***	
1	Materials	28.3	26.1	2.2
2	Labour	150.8	123.1	27.7
3	Contingency	13.9	2.6	11.3
4	Interest During	6.4	3.7	2.7
5	**Total Direct Capital Cost**	**199.5**	**155.5**	**44.0**
6	Indirect Overheads	48.0	33.4	14.6
7	**Total Project Cost**	**247.5**	**188.9**	**58.6**
8	Total Cost per km	13.0	9.4	3.6
9	Material Cost per km	1.5	1.3	0.2
10	Labour, External permitting and land, and Outside Services per km	7.9	6.2	1.7
11	**Total Ancillary Facilities Direct Capital Cost**	**89.7**	**127.1**	**(37.4)**
12	Ancillary Facilities Indirect Overheads	20.8	23.3	(2.5)
13	**Total Ancillary Facilities Project Cost**	**110.5**	**150.4**	**(39.9)**
14	**Total Project Cost (Mainline and Ancillary Facilities) $ Millions**	**358.0**	**339.3**	**18.7**

Notes:
1. The proposed Project mainline estimate is inclusive of the Richardson Sideroad end point valve site.
2. The proposed Project has a more complex mainline scope with eight (8) trenchless crossings compared to one (1) trenchless crossing for the Dawn to Corunna Replacement Project.
3. Reduced contingency for the Dawn to Corunna Replacement Project due to its current stage of development/execution.

In its evidence, Enbridge Gas highlighted three primary reasons for the variance in cost between the two projects: (i) the construction of the Richardson Valve Site Station; (ii) the Project's mainline is more complex with seven more trenchless crossings than Dawn to Corunna; and (iii) a reduced contingency for Dawn to Corunna given the later stage of development. These three differences account for $37.3 million of the $44.0 million difference in total direct capital cost estimates between the two projects.[77]

[77] Enbridge Gas quantified: (i) the direct capital cost of the Richardson valve site station at $10.0 million (see Undertaking response Exhibit J3.1); (ii) the incremental cost of the additional trenchless crossings at $16.0 million (see Undertaking response Exhibit J3.2); and (iii) contingency difference at $11.3 million (see Exhibit E, Schedule 1, Tab 1, page 2)

In its initial application filed in June 2022, Enbridge Gas estimated the cost of the Project (that initially included 12 km of NPS 16 pipeline (Leamington Interconnect), which was eliminated in the application update) to be $246.6 million, which has now increased to $358.0 million.[78] Enbridge Gas attributed the variances between that amount and the current estimate to: (i) bid to estimate variance; (ii) unforeseen inflation; and (iii) scope refinement. In particular, after the filing of its initial application, Enbridge Gas conducted a RFP inviting seven proponents to bid. Six proponents submitted bids on the RFP. The average proposal price from the "three most competitive proponents" was used in calculating the current $358.0 million cost estimate. In response to an undertaking, Enbridge Gas filed, on confidential basis, an itemized capital cost estimate for the Project based on the lowest cost bid submitted by one of the three most competitive proponents. Enbridge Gas emphasized that all three proponents were qualified in terms of their technical expertise and the price is not the only determining factor in selecting the proponent and awarding the construction contract.[79]

OEB Staff Submission

OEB staff initially had questions about the 45% increase in construction costs from the original application filed in June 2022 to the updated application filed in June 2023. However, a full review of the evidence has led OEB staff to conclude the estimated capital cost for the Project is reasonable - subject to two modifications discussed below. The increase in the current cost estimate is driven, at least in part, by the bids that were received in response to the RFP for a contractor for the Project and, as such, reflect changes to market conditions.

OEB staff further notes that the current cost estimate for the Project is largely in line with estimate for the Dawn to Corunna project, when adjusted for differences in scope and timing between the two projects. The comparison of the costs for the two projects is meaningful as they are similar in terms of length (19 km vs 20 km), size of the pipeline (NPS 36), location and construction date.

There are however two modifications that OEB staff submits should be applied to the costs of the Project. First, OEB staff submits that the cost estimate to be used for ratemaking purposes (assuming the final costs are not known and considered by the OEB before the costs begin to be recovered in rates) and by which the final construction cost should be compared is the cost estimate using the lowest cost qualified proponent. This amount has been filed in confidence[80] as Enbridge Gas has not entered into a

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[78] Enbridge Gas response to interrogatory I.SEC.2 a), page 2
[79] Exhibit E, Schedule 1, Tab 1; Enbridge Gas response to interrogatory I.SEC.1; Undertaking response Exhibit J3.3; Undertaking response Exhibit J3.4
[80] Undertaking response Exhibit J3.3

binding contract with a proponent. However, OEB staff submits that this confidentiality need only be maintained until the contract is executed. OEB staff submits that a cost estimate based on the average bid of the three most qualified proponents provides for an additional, and unnecessary, contingency on top of the contingency already allocated to the Project. Ultimately, the prudent course for Enbridge Gas is to execute a contract with the lowest cost qualified proponent. The Project cost estimate should be based on that reality.

Second, the issue of indirect overhead capitalization is currently being adjudicated in Enbridge Gas's rebasing application.[81] OEB staff submits that any decision in that proceeding which changes how overheads are capitalized should be applied to the overheads estimated for the Project.

Project Economics

In the sub-sections that follow, OEB staff summarizes Enbridge Gas's evidence regarding the economic assessment of the Project, the applicability of the current OEB-approved methodologies to assess the economic feasibility of natural gas facility projects, and the appropriateness of requiring CIAC payments from contract customers that are driving the need for the Project and provides its position on these matters.

Enbridge Gas's Economic Assessment[82]

The total estimated cost of the Project is $358.0 million. Enbridge Gas defined the Project as a transmission system expansion and applied the three-stage economic test set out in E.B.O. 134 (E.B.O. 134 test) to evaluate Project economics.[83] The results of the E.B.O. 134 test are set out in Table 8 below.[84]

Table 8
E.B.O. 134 Test Results

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

Enbridge Gas stated that the Project is in the public interest and is economically

[81] EB-2022-0200
[82] Exhibit E, Tab 1, Schedule 1
[83] Exhibit E, Tab 1, Schedule 1, page 7, paragraph 24
[84] Exhibit E, Tab 1, Schedule 1, page 7

feasible as the result of the E.B.O. 134 test is a net present value (NPV) benefit in the range of $333 million to $460 million.

In Stage 1 of the E.B.O 134 test, Enbridge Gas conducted a Project-specific Discounted Cash Flow (DCF) analysis. The 40-year DCF resulted in $150 million revenue shortfall. The main indicator resulting from the DCF in Stage 1 is a Profitability Index (PI). The PI is calculated by dividing the NPV of the cash inflows by NPV of cash outflows. The PI for the Project is 0.44 which implies that the Project is not economic at Stage 1 of the analysis. The revenue horizon that Enbridge Gas used for the Stage 1 analysis was 40 years. Enbridge Gas also provided a DCF analysis using a 20-year revenue horizon, which would result in an $174 million shortfall and a PI of 0.39.[85]

As the PI for the Project was below 1.0, Enbridge Gas conducted the Stage 2 cost/benefit analysis in accordance with the E.B.O. 134 test. The Stage 2 analysis categorizes energy cost savings to in-franchise general service customers as benefits associated with the Project.[86] The savings were calculated based on using natural gas instead of another fuel. Enbridge Gas estimated that the energy cost savings were $226 million and $353 million for a 20-year and 40-year horizon respectively.[87]

The Stage 3 analysis involved monetizing the value of other public interest considerations. More specifically, Enbridge Gas quantifies the direct impacts of the Project on Gross Domestic Product (GDP) and taxes paid by the utility in Ontario. Project. Enbridge Gas estimated that economic benefits to Ontario are approximately $257 million. The economic benefit of $257 million is only related to the construction of the Project and does not include the economic benefits to Ontario when natural gas customers receiving the incremental supply invest and grow their operations. Enbridge Gas estimated that the total direct capital investment from these connecting customers would be $4.5 billion.[88]

Environmental Defence questioned Enbridge Gas's assumptions for the Stage 2 analysis under the E.B.O. 134 test, and filed evidence from Dr. McDiarmid using alternative assumptions.[89] The primary difference in the assumptions between Enbridge

[85] Exhibit I.EP.15
[86] Enbridge Gas did not include energy cost savings for contract customers in the Stage 2 analysis, indicating that these customers will not choose an alternative fuel if natural gas is not available to them, but would instead expand or move their operations to other jurisdictions, likely outside of Ontario, where their natural gas needs can be served. Exhibit E, Tab 1, Schedule 2, page 5
[87] Exhibit E, Tab 1, Schedule 1, pages 4-5
[88] Exhibit E, Tab 1, Schedule, 1 pages 5-6
[89] Environmental Defence Intervenor Evidence (EB-2022-0157), prepared by McDiarmid Climate Consulting: Evidence Regarding Stage 2 Analysis and Gas Alternatives for Greenhouses, updated October 18, 2023,

Gas's and Dr. McDiarmid's analysis is that Enbridge Gas assumed that in the absence of access to natural gas, potential general service customers would instead use a mixture of electricity, propane, and heating oil in proportion to the current shares of household space heating energy options based on Statistics Canada data on household energy use.[90] Dr. McDiarmid, noting that the incremental general service demand that would be served by the Project is more than 95% new construction, applied the assumption that residential and commercial customers would instead choose high-efficiency electric heat pumps.[91] Under this assumption, Dr. McDiarmid concluded that customers would actually experience higher energy bills were they to use natural gas instead of heat pumps, and that the Stage 2 results for the Project would be negative.

Some intervenors also questioned the appropriateness of Enbridge Gas's Stage 3 analysis, which calculates the economic benefit based on the proportion of the Project's capital spending in Ontario. Under this approach, the higher the Project cost is, the greater the Stage 3 benefit that results.[92]

Applicability of the OEB-approved Economic Tests and the Requirement for a CIAC

In Procedural Order No. 4, the OEB confirmed that the issue of the applicability of the E.B.O. 134 and E.B.O. 188 economic tests is within the scope of the proceeding. The OEB stated, "...the OEB is of the view that the economics of the project, the applicability of EBO 134 and EBO 188, and the extent to which contributions in aid of construction should be required are issues that are in scope for this proceeding. Enbridge may wish to consider whether to provide additional evidence on those issues as part of its proposed update to its application. Enbridge may also wish to consider whether it should be communicating with potentially affected customers regarding the position of some parties that contributions in aid of construction should be required."[93]

In the updated application, filed on June 16, 2023, Enbridge Gas addressed the issue of the applicability of the E.B.O. 134 and E.B.O. 188 economics tests. Enbridge Gas stated that E.B.O. 134 is the appropriate economic test as the Project is entirely a transmission project.

In addition, as part of the 2023 EOI, Enbridge Gas conducted outreach to customers to obtain their position on paying CIAC. Enbridge Gas asked these customers how a

[90] Exhibit I.Staff.15c. Enbridge Gas's calculations also assumed that electric heating would be resistance heating, rather than higher-efficiency heat pumps.
[91] Dr. McDiarmid's evidence did not change Enbridge Gas's assumptions regarding the alternatives for industrial buildings, noting that, in these cases, fuels may be used for applications where heat pumps may not be suitable.
[92] Oral Hearing Transcript, Vol. 3, pages 181-182
[93] Procedural Order No. 4, December 14, 2022, page 3

requirement for a CIAC may impact their demands for new/incremental service.[94] Enbridge Gas stated that the customers feedback was as follows:

- Customers submitting EOI bids for new/incremental service were bidding under the assumption that the OEB would apply the established regulatory framework for transmission system expansion projects, which does not require CIAC, consistent with similar projects constructed in the past
- Customers generally indicated opposition to being required to provide CIAC to support transmission system expansion in this instance
- No customer indicated that they would be willing to provide a CIAC for a transmission system expansion project without understanding the magnitude of the CIAC and the unique justification for its selective application in this instance.

Some intervenors questioned the appropriateness of applying E.B.O. 134 as the economic test for the Project.[95] Other intervenors supported Enbridge Gas's position that the E.B.O. 134 is the appropriate test to assess the economics of the Project.[96]

Enbridge Gas maintained its position that the Project is a transmission project and that it would benefit both contract and general service customers. Enbridge Gas stated that CIAC should not be required as the Project is a transmission project and the entire Panhandle market will benefit from the incremental capacity. Enbridge Gas noted that the pipeline provides service to a large geographic area and connects to multiple distribution systems serving both contract and general service customers. Enbridge Gas also emphasized that the Project partially alleviates the largest Panhandle system bottleneck which improves reliability of service for existing customers and enables growth of demand for both existing and new customers.

Some intervenors explored through interrogatories and cross-examination the issue of how a CIAC could be calculated and applied to customers connecting to the Project. Enbridge Gas responded that calculating a CIAC for a customer connecting to a transmission project is not appropriate "…and not possible under the current regulatory perspective." [97] More specifically, Enbridge Gas stated that, "[t[he contribution and the methodology to calculate the contribution is in effect a rate that must be approved by

[94] Exhibit E, Tab 1, Schedule 1, B. Project Economics, paragraph 4, page 3

[95] Energy Probe. Oral Hearing Transcript, Vol. 1, page 23 lines 10-25 and page 24, lines 2-9; Environmental Defence, Oral Hearing Transcript, Vol. 1, page 25, lines 23-28 and pages 26-28; IGUA, Oral Hearing Transcript, Vol. 1, pages 31-33; SEC, Oral Hearing Transcript Vol. 1, page 43, lines 1-7; Pollution Probe, Oral Hearing Transcript, Vol. 3, page 17, lines 9-16; Three Fires Group, Oral Hearing Transcript, Vol. page 47, lines 12-23

[96] APPrO, Oral Hearing Transcript, Vol. 1, November 13, 2023, page, 15 lines 10-28 and page 16, lines 1-4; Atura, Oral Hearing Transcript, Vol.1, November 13, 2023, page 20, lines 7-13; OGVG, Oral Hearing Transcript, Vol. 1, page 34, lines 25-28

[97] Enbridge Gas response to interrogatory I.ED.29, October 3, 2023

the OEB as being just and reasonable. If Enbridge Gas were to provide a number (even if one could be calculated) it would be highly speculative, a departure from past practice, and would represent to customers a rate that has never been considered and is not approved by the OEB."[98]

OEB Staff Submission

OEB staff submits that the OEB should accept Enbridge Gas's categorization of the Project as a transmission project and the E.B.O. 134 test should be applied. OEB staff submits that the Project is economically justified under the E.B.O. 134 test and should be approved with no requirement for CIAC payments.

OEB staff notes that the Project is best categorized as a "dual purpose" pipeline. As discussed in detail in the need section of the submission, 94% of the demand that will be served by the Project is related to identifiable contract customers. It is these contract customers that are driving the need for the Project and relatedly, the Project costs to be incurred. However, OEB staff acknowledges that these contract customers are not going to directly connect to the Project.[99]

The OEB, today, does not have an economic test that is applicable to dual purpose pipelines. The application of an economic testing approach (inclusive of the requirement for the CIAC payments) to the Project that reflects the fact that it is a modest number of identifiable contract customers that are driving almost the entire need for the Project and giving rise to the majority of the associated Project costs could be useful in these circumstances. However, OEB staff submits that this not the appropriate time to apply a new approach as it could result in adverse impacts to Ontario's economy as it is possible that some of these contract customers that underpin the need for the Project will choose not to connect if a capital contribution is applied and this will hinder their planned growth in Ontario.

More specifically, OEB staff agrees with Enbridge Gas that if the Project is not undertaken, some contract rate customers[100] that rely on access to natural gas may not expand in Ontario and may move their operations to other jurisdictions, outside of Ontario, where their natural gas needs can be served. Enbridge Gas noted that as a consequence, the province of 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 Ontario, or the resulting 6,900 jobs also

[98] Enbridge Gas response to interrogatory I.ED.29, a) and b), page 2, October 3, 2023
[99] Enbridge Gas response to interrogatory I.PP.39 b)
[100] OEB staff notes that the Project supports growth in the power generation, greenhouse and automotive sectors.

identified.[101]

OEB staff notes the emphasis placed by the Ontario Government on economic growth and job creation, including as described in the Minister of Energy's letter of direction to the OEB as follows:

> Our government has ambitious goals to build at least 1.5 million new homes, new highways, subways and improved rail transportation, and has also been successful in attracting new jobs to the province, particularly in critical minerals, electric vehicles and battery manufacturing. With this in mind, 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.[102]

OEB staff notes that the Project also supports the Ontario Government's direction to the IESO to procure 1,500 MW of natural gas fired generation capacity for 2025 to 2027 in-service dates.[103] OEB staff notes that 53% of the total incremental capacity created by the Project will support three natural gas fired generators in supplying electricity to homes and businesses in Ontario.[104]

In addition, OEB staff submits that applying a new approach to economic testing (and requiring CIAC payments) for dual purpose pipelines in the context of the current proceeding raises a fairness issue for the potential connecting contract customers. These contract customers have submitted EOI bids, or have already signed contracts for service with Enbridge Gas, for new/incremental service from the Project under the assumption that the OEB would not require a CIAC. If a decision is rendered that requires the payment of a CIAC from these contract customers, these customers will have participated in this bidding process in the absence of full information.

For these reasons, OEB staff submits that the OEB should accept Enbridge Gas's categorization of the Project as a transmission project and the E.B.O. 134 test should be applied. OEB staff submits that this finding would be in accordance with past OEB treatment of dual purpose pipelines.[105]

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[101] Exhibit B-1-1, p. 15 and Exhibit E-1-1, page 6
[102] Letter of Direction, November 29, 2023
[103] Exhibit B, Tab 1, Schedule 1, page 17, paragraph 57; see also Powering Ontario's Growth report which notes "There is currently no like-for-like replacement for natural gas and the IESO has concluded it is needed to maintain system reliability until nuclear refurbishments are complete and new non-emitting technologies such as storage mature." (page 49)
[104] Enbridge Gas response to interrogatory I.STAFF.24 a) Table 1: 2024 and 2025 Incremental Customer Demand Requirements (Underpinned by Firm Distribution Contract and in Negotiation) by Customer by Sector
[105] For example, Kingsville Leave to Construct (EB-2018-0013)

OEB staff notes that the OEB has grappled with the issue of what economic test should apply to projects that serve multiple purposes in the past. For example, Union Gas Limited's (Union) Kingsville project[106] has similarities to the Project. In the Kingsville proceeding, the OEB noted that the need for that project was supported by the identified 14 executed contracts for firm service and an additional 20 contracts under negotiation (i.e., contract customer demand). In addition, the Kingsville project was noted to support growth in the greenhouse sector.[107] This is similar to the current Project, where the need is underpinned predominantly by contract customer demand (in the power generation and greenhouse sectors).

In the background included as part of the Decision and Order for the Kingsville project, the OEB noted the following:

> As the Project addressed both transmission and distribution needs, the OEB questioned Union's use of the E.B.O. 134 test exclusively, with no reference to the OEB's economic test for distribution applications (E.B.O. 188 test). The OEB also asked Union whether it had sought contributions-in-aid of construction, an element of the E.B.O. 188 test.
>
> Union responded that the E.B.O. 188 test for distribution applications did not apply to this application for a transmission line. Union stated that it was not appropriate to apply the E.B.O. 188 test as the incremental forecast demand extended throughout the Panhandle service area and no distribution customers would be connected directly to the new pipeline.
>
> …
>
> IGUA submitted that if the OEB concludes that the Project serves both transmission and distribution functions, a more nuanced approach to economic evaluation and associated cost responsibility requirements might be warranted. IGUA provided an example whereby 10% of the cost was recovered through contributions-in-aid of construction from the 34 customer contracts dependent on capacity enabled by the Project. IGUA submitted that contributions-in-aid of construction would reduce the shortfall in the stage 1 analysis and improve the PI for the Project.[108]

The findings state:

> The OEB finds that Union appropriately followed the OEB's E.B.O. 134 test for transmission projects. While the stage 1 analysis results in a net present value of negative $59.4 million and a P1 of only 0.44 over 40 years, broader economic benefits identified in the stage 2 analysis support the approval of the Project.
>
> While the OEB has approved the Project, there are some concerns that the OEB would like to observe.
>
> First, the new pipeline has ancillary distribution benefits according to Union in addition to

[106] EB-2018-0013
[107] EB-2018-0013, Decision and Order, September 20, 2018, page 4. A difference between the two projects, is that in the Kingsville proceeding, Union acknowledged that the project serves distribution needs (see EB-2018-0013, Board Panel Question 3), whereas there has been no such acknowledgment in the current proceeding.
[108] EB-2018-0013, Decision and Order, September 20, 2018, pages 4-5

> the transmission functions. The distribution benefits are evident as Union identified 14 firm customer contracts executed and 20 customer contracts being negotiated which rely on the approval and construction of the Project. The OEB finds that the Project meets both distribution and transmission needs, yet the OEB's economic tests are exclusive, applicable to either distribution or transmission lines.
>
> Second, the economic test for transmission, E.B.O. 134, does not attribute who should pay with each stage of testing. For distribution pipelines, the more recent E.B.O. 188 test recognizes that if there is insufficient new revenue generated by the project to cover its costs, capital contributions are required from the benefiting parties. Under E.B.O. 134, the stage 2 benefiting parties would be downstream connecting customers and the local economy. Currently there is no mechanism to have these parties make a contribution to the costs despite their substantial benefit.
>
> For natural gas in Ontario, no economic test or ratemaking mechanism exists today to allow these discrepancies to be addressed.
>
> The OEB acknowledges the creative thinking included in IGUA's submission. While it is not appropriate to split the costing between transmission and distribution pipelines as proposed by IGUA in this proceeding, such proposals may help inform future thinking on the treatment of dual function pipelines.[109]

With respect to the Kingsville project, the Decision and Order was clear that the OEB was aware that the project served dual purposes and, nonetheless, went ahead and applied the E.B.O. 134 test.[110] The OEB should do the same thing here with respect to the Project.

OEB staff submits that any change to the approach to economic testing for dual purpose pipelines should be addressed in a generic proceeding (or consultation) that is designed to review the E.B.O. 134 and E.B.O. 188 economics tests and consider their applicability to these types of pipelines going forward. In this way, when customers are seeking service from Enbridge Gas, and incremental capacity is required to serve that demand, the OEB's framework will be known in advance of any EOI or contracting activities (and the fairness issues described previously will be avoided).

OEB staff acknowledges that it is not ideal to further delay an update to the E.B.O. 134 and E.B.O.188 economic tests. However, Enbridge Gas's first consolidated rebasing proceeding is currently being adjudicated. OEB staff submits that it would be preferrable to consider revisions to these tests in a generic manner after certain relevant issues (i.e., energy transition-related matters including revenue horizon) have been adjudicated in the rebasing proceeding.[111]

As noted previously, OEB staff is of the view that the Project is economically justified as

[109] EB-2018-0013, Decision and Order, September 20, 2018, pages 5-6
[110] EB-2018-0013, Decision and Order, September 20, 2018, pages 5-6. Though, the OEB noted that there should be "future thinking" on the treatment of dual purpose projects.
[111] EB-2022-0200

it has a positive NPV under the E.B.O. 134 test. OEB staff submits that the three-stage E.B.O. 134 assessment shows that, cumulatively and inclusive of the economic benefits of the Project, the benefits outweigh the costs. OEB staff acknowledges that the approach used by Enbridge Gas is consistent with that used in previous Leave to Construct applications. However, OEB staff has several concerns with Enbridge Gas's methodology as applied to the Project, which when corrected, result in a lower, but still positive NPV.

First, OEB staff submits that the Stage 1 NPV should be based on a 20-year revenue horizon (as opposed to a 40-year revenue horizon), consistent with the fact that 94% of the demand that will be served by the Project is related to identifiable contract customers. This is consistent with the E.B.O. 188 test that uses 20-year revenue horizon for large volume customers, to recognize the greater uncertainty for large volume customers as to whether the demand will persist for a 40-year period. With a 20-year revenue horizon, the Stage 1 NPV would be negative $174 million[112] (as opposed to negative $150 million resulting from a 40-year revenue horizon).

Second, OEB staff submits that Enbridge Gas's estimate of the Stage 2 NPV benefits is too high, because its assumptions about the energy sources that would be used by general service customers in the absence of natural gas are not reasonable. OEB staff agrees with the assumption in Dr. McDiarmid's evidence that, given that these buildings would be almost entirely new construction, electric heat pumps (not propane, heating oil, or electric resistance heating) are the most likely energy choice if natural gas is not available. OEB staff agrees with Enbridge Gas that it is appropriate to set a floor of zero for Stage 2 NPV benefits (rather than calculating a negative Stage 2 NPV, as suggested by Dr. McDiarmid's calculations), as these buildings may choose not to connect to the natural gas system if their energy bills would be lower by not connecting.[113]

Third, OEB staff is concerned with Enbridge Gas's methodology for calculating Stage 3 economic development benefits. Enbridge Gas's practice of calculating a Stage 3 GDP benefit that is based on the direct capital cost of the Project to Enbridge Gas is likely unbalanced. Increased capital spending by Enbridge Gas that must be recovered from rates translates into less disposable income for utility customers to spend on other products or services, which would likely negatively impact GDP, yet there is no Stage 3 adjustment for this factor. OEB staff further notes that Enbridge Gas's methodology has a bias towards capital solutions for Enbridge Gas (as opposed to OM&A solutions), as only capital spending is credited with a GDP benefit. Finally, the high value of the multiplier (91% of the project capital cost) almost entirely negates the Stage 1 project

[112] Exhibit I.EP.15
[113] Enbridge Gas Argument-in-Chief, page 29.

cost, regardless of the specifics of a project, when the three stages of the test are added together (i.e., almost any project with a minimal level of incremental revenue would pass the test). Similar concerns with Enbridge Gas's Stage 3 methodology have also been raised by the IRP Working Group.[114]

However, regardless of the concerns described above, OEB staff notes that Enbridge Gas's Stage 3 analysis for the Project does not include the indirect economic development benefits associated with expansion of greenhouse production. Enbridge Gas qualitatively identified these benefits but did not monetize them in the Stage 3 analysis, as it does not have an accepted mechanism for doing this calculation that has been accepted by the OEB.[115] Enbridge Gas believes that the economic benefits of the $4.5 billion in capital spending enabled by the Project will be at least equal to if not greater than the $257 million in economic benefits it has calculated would result from the construction of the Project.[116] OEB staff agrees with Enbridge Gas, and therefore submits that a floor for the Stage 3 NPV benefits is $257 million.

OEB staff does not take a position on all of the differences between the analyses conducted by Enbridge Gas and by Dr. McDiarmid,[117] and notes that some of these issues, as well as the concerns identified above by OEB staff, are likely to be addressed as Enbridge Gas develops a DCF+ test as part of the IRP Framework that will be reviewed by the OEB in a future proceeding.

For the purposes of this proceeding, OEB staff believes the assumptions it made are reasonable, and therefore concludes that the Project has a positive NPV in accordance with the E.B.O. 134 test. Table 9 below provides a comparison of the results of Enbridge Gas's and OEB staff's E.B.O. 134 testing.

Table 9
E.B.O. 134 Test Comparison

Stage ($millions)	Enbridge Gas Proposed	OEB Staff Proposed
1	($150)	($174)
2	$226 to $353	>= $0
3	$257	>= $257
Total	**$333 to $460**	**>= $83**

[114] Use of the Discounted Cash Flow-Plus Test in Integrated Resource Planning (IRP): Report of the IRP Technical Working Group, May 30, 2023, pages 62-63
[115] Oral Hearing Transcript, Vol. 1, pages 144-146
[116] Exhibit I.OGVG.5
[117] Enbridge Gas Argument-in-Chief, pages 28-31

Calculation of CIAC in the context of an Alternative OEB Finding

OEB staff notes that some intervenors may suggest that CIAC payments should be required for the Project. While OEB staff does not agree with this position, to be of assistance to the OEB, OEB staff has provided its views on how this could be operationalized in the current proceeding in the scenario that the OEB determines that CIAC payments from contract customers related to the Project are appropriate now.

With respect to the Project, Enbridge Gas's evidence highlights that 94% of the capacity to be added by the Project is for large contract customers and only 6% is expected to serve the general service market. In this context, the Project serves a dual purpose – while there is no question that it provides transmission benefits to the Panhandle region (i.e., alleviates a Panhandle system bottleneck, which improves reliability and enables growth of demand for both existing and new customers) - the fact is that the majority of the benefit will accrue to the few contract customers that underpin the need for the Project.

OEB staff notes that questions were raised during the proceeding as to whether there is a risk of the Project becoming underutilized or stranded in the future, should demand from contract customers decline due to energy transition considerations (e.g., if carbon pricing makes food production in heated greenhouses uneconomic, or if the forthcoming federal clean electricity regulations lead to declines in natural gas use by the power generation sector), and how Enbridge Gas has considered this risk. Enbridge Gas indicated that it has no basis to believe that the Project will be undersubscribed or stranded, and thus did not complete a risk assessment of the possibility of asset stranding.[118] Enbridge Gas further submitted that the current demand forecast and depreciation rates in its application appropriately reflect the known energy transition risk at this time, but that if a reliable forecast of energy transition-related impacts on demand were available, Enbridge Gas would be willing to take on the risk of future underutilization as long as it also had the ability to mitigate that risk.[119]

OEB staff notes that should the Project become partially stranded or underutilized due to declining demand from contract customers as a result of the energy transition, the Stage 1 NPV of the Project (i.e., -$150 million) and the level of cross-subsidization from existing customers would necessarily increase further. The potential to mitigate stranded asset risk (that would be borne by customers not driving the need for the Project) is an argument that some intervenors may use to support the requirement for CIAC payments for the Project and to apply it now (instead of waiting for some point in the future to change the approach to dual purpose pipelines).

[118] Exhibit I.PP.43
[119] Exhibit J3.5

In the scenario that the OEB does require CIAC payments from contract customers that are underpinning the need for the Project, OEB staff submits the following methodology should be applied for the purposes of calculating the appropriate total CIAC to be paid by the contract customers:

- The capital cost of the Project is divided between contract customers and general service customers on the basis of the percentage of the Project-related incremental capacity that will serve each of these customer categories (i.e., 94% contract and 6% general service).
- A Stage 1 analysis is undertaken whereby the capital costs assumed are only those capital costs that are associated with the contract customers.
    - A 20-year revenue horizon is used as that is consistent with the revenue horizon applied to large volume customers in the E.B.O. 188 test.
- A total CIAC is calculated based on ensuring that the resulting PI in the Stage 1 analysis is 1.0.

OEB staff notes that applying this approach would ensure that the contract customers are responsible for paying a CIAC amount that results in those customers paying for the portion of the Project costs that they directly benefit from and are otherwise not recovered through the revenues received by Enbridge Gas through the rates charged to these customers. The remaining Project cost is socialized amongst Enbridge Gas's customer base.[120]

OEB staff notes that the above approach allows for the calculation of the total CIAC for which contract customers will be responsible. What it does not do is set out a proposed methodology for calculating the CIAC that should be applied to the individual contract customers that connect to Enbridge Gas's system that benefit from the incremental capacity created by the Project. OEB staff does not debate that designing this methodology will be challenging. However, OEB staff does not believe that doing so is impossible.

OEB staff suggests that it should be Enbridge Gas's responsibility to propose a fair and implementable approach. On that basis, the OEB could set out, in its decision, the guiding principles for this customer-specific CIAC calculation and Enbridge Gas would file a proposal for this calculation (along with the total CIAC that is required to bring the Project to a PI of 1.0 in the Stage 1 analysis) in a streamlined Phase 2 of the

[120] OEB staff notes that a slight modification to the above approach that the OEB could consider is to require a total CIAC that brings the PI up to a level that is lower than 1.0. For example, the OEB could elect to use a PI of 0.8 (or really, any PI less than 1.0 that it believes is reasonable), which operates to reduce the total CIAC required from the contract customers and relatedly, socializes more of the Project cost across Enbridge Gas's customer base. The rationale for potentially using a lower PI is to apply a greater recognition of the transmission benefits of the Project, which are properly socialized across Enbridge Gas's customers.

proceeding for OEB approval.[121] OEB staff suggests that these guiding principles should be high-level and provide Enbridge Gas with the needed flexibility to design a methodology that is both fair and implementable. OEB staff suggests that the guiding principles include: (i) a statement that Enbridge Gas should, using the best information that is it has available, allocate the total CIAC to contract customers in a manner that recognizes which customer causes the cost to be incurred; and (ii) reflect refund provisions whereby customers that connected earlier may be refunded a portion of the CIAC when other customers come online later and reasonably should have contributed towards the Project cost had they connected at the outset.

3.4 Environmental Impacts

AECOM Canada Limited was retained by Enbridge Gas to complete the Environmental Report and the consultation process in accordance with the OEB's Environmental Guidelines (7th Edition).[122]

The Environmental Report assessed the existing bio-physical and socio-economic environment in the study area, the alternative routes, proposed the preferred route, conducted public consultation, conducted impacts assessment and proposed mitigation measures to minimize the impacts.

On April 29, 2022 Enbridge Gas distributed the Environmental Report to the members of the Ontario Pipeline Coordinating Committee (OPCC), affected conservation authorities, municipalities and other stakeholders for review and comments. Enbridge Gas also conducted, as part of the consultation, virtual open house sessions held on November 17, 2021 to December 3, 2021 and on February 14, 2022 to February 28, 2022.

Enbridge Gas stated that it did not conduct additional public consultation on the updated application filed on June 16, 2023.[123] However, Enbridge Gas sent a letter describing the updated scope of the Project[124] to OPCC members, affected municipalities, conservation authorities, landowners, Indigenous communities, and other local agencies. Enbridge Gas filed a summary of the comments received as of June 5, 2023

[121] In this scenario, OEB staff envisions a draft rate order-type process whereby Enbridge Gas makes its proposal, OEB staff and intervenors are given an opportunity to make submissions, Enbridge Gas has the opportunity to reply and then the OEB issues its decision.
[122] Exhibit F, Tab 1, Schedule 1, pages 1-2. Enbridge Gas noted that the OEB released the 8th Edition of the Environmental Guidelines for the Location, Construction, and Operation of Hydrocarbon Pipelines and Facilities in Ontario in March 2023, after the initiation, consultation and finalization of the Project and associated Environmental Report.
[123] Enbridge Gas response to interrogatory I.STAFF.29 a)
[124] The scope of the Project was updated in June 2023 to exclude the Leamington Interconnection pipeline.

in the updated application.[125] Enbridge Gas also advised that no updates to the comments were received since June 5, 2023.[126]

Enbridge Gas provided a summary of the status of receiving the necessary permits and approvals for construction.[127] Enbridge Gas stated that it will obtain all the permits and approvals prior to the start of construction by March 31, 2024. Enbridge Gas noted that clearance from the Ministry of Citizenship and Multiculturalism (MCM) for archeological surveys and assessments at the Richardson Sideroad Valve Site Station and adjacent lands may not be obtained by March 31, 2024. The reason is that Enbridge Gas has not obtained agreement from a landowner to access to the lands at the planned location of the Richardson Sideroad Station to complete the archeological survey. However, Enbridge Gas expects to receive approval for early access from the OEB and submit the Archeological Survey report to the MCM so that MCM can grant clearance for archeology at that site by the summer of 2024.[128]

The Environmental Report incorporates mitigation measures and commits to development of an Environmental Protection Plan (EPP) prior to the construction start. The EPP will be used to implement the specific mitigation measures during construction of the Project. The EPP will be communicated to the Environmental Inspector who will assist the project manager in ensuring that the mitigation measures are implemented.

OEB Staff Submission

OEB staff submits that Enbridge Gas has completed the Environmental Report in accordance with the OEB Environmental Guidelines. OEB staff submits that it was appropriate for Enbridge Gas to utilize the 7th Edition of the OEB's Environmental Guidelines as the 8th Edition was not released until after the initiation, consultation and finalization of the Project and associated Environmental Report.

OEB staff has not identified any concerns with the environmental aspects of the Project. Enbridge Gas has stated that it is committed to implementing the mitigation measures set out in the Environmental Report and to completing the EPP prior to the start of construction.

OEB staff also notes that, as a standard condition of approval for this application, Enbridge Gas will be required to obtain the required permits and approvals for the Project.

[125] Exhibit F, Tab 1, Schedule 1, page 2, paragraph 5 and Attachment 2
[126] Enbridge Gas response to interrogatory I.STAFF.28, a)
[127] Enbridge Gas response to interrogatory I.STAFF.21, a), b),c), d), pages 1-3
[128] See the Land Matters section in this submission for additional information on the Richardson Sideroad Station land access issue and application by Enbridge Gas for early access to these lands.

3.5 Landowner Matters

Enbridge Gas will require approximately 19 kilometres of 23 metres width of permanent easement translating to 42.0 hectares (104 acres) for the Project to ensure safety and to provide necessary working space for maintenance. Enbridge Gas will also require 71.6 hectares (177 acres) of temporary easements for construction and topsoil storage.

Enbridge Gas filed forms of temporary land use[129] and permanent easement[130] agreements. The same form of agreements were approved by the OEB in a previous proceeding, Enbridge Gas's Haldimand Shores Community Expansion Project.[131]

Enbridge Gas noted that it requires early access land rights for the purposes of conducting environmental and engineering examinations and surveys, necessary for fixing the site and completing relevant approvals.

To date, Enbridge Gas has obtained early access land rights and has entered into easement and temporary land use agreements with 53 of the 56 affected property owners. For the three properties located at the proposed construction site of the Richardson Side Road Valve Site Station (Richardson Sideroad Properties), Enbridge Gas has not secured early access land rights and is unable to conduct the necessary survey such as the archeological survey. These properties are adjacent to one another and are owned by related parties under common control. Enbridge Gas has corresponded with this landowner since January 2022 and negotiations have not progressed to a stage where early access rights have been granted. The landowner of these three properties is the registered intervenor in the proceeding (Courey Corporation).

Enbridge Gas stated that the major restrictions imposed on the landowner by the permanent easement agreement are that the landowner cannot erect buildings or privacy fencing on the easement and cannot excavate or install field tile without prior notification to Enbridge Gas. Enbridge Gas stated that the landowner is free to farm the easement or turn it into a laneway.

On June 16, 2023, Enbridge Gas filed an application with the OEB under section 98(2) of the OEB Act (Early Access Application) for an order authorizing entry onto the properties to complete the necessary examinations and surveys.[132] Enbridge Gas's early access proceeding has been in abeyance since August 29, 2023 at Enbridge Gas's request.

[129] Exhibit G, Tab 1, Schedule 1, Attachment 4
[130] Exhibit G, Tab 1, Schedule 1, Attachment 3
[131] EB-2022-0088, Decision and Order, dated August 18, 2022
[132] EB-2022-0285

On December 8, 2023, Enbridge Gas filed with the OEB an update to its Early Access Application requesting that the proceeding be taken out of abeyance and that the OEB grant Enbridge Gas access to these properties by April 2024.[133]

Enbridge Gas stated that if leave to construct is granted before Enbridge Gas is able to secure the necessary land rights with this landowner, it will need to seek leave from the OEB to expropriate such land rights under section 99 of the OEB Act. Enbridge Gas noted that any expropriation proceeding could impact the November 1, 2024 in-service date for the Project and Enbridge Gas would need to employ a temporary contingency plan to ensure Winter 2024/2025 demands are met.

OEB Staff Submission

OEB staff submits that Enbridge Gas appears to be appropriately managing land-related matters. OEB staff notes that Courey Corporation, an intervenor in this proceeding, is representing the interests of the three Richardson Sideroad Properties, and will have an opportunity to provide its written submission on this issue. OEB staff also notes that the standard conditions of approval require that Enbridge Gas secure all necessary land rights required for the construction of the Project.

OEB staff submits that the OEB should approve the proposed forms of permanent easement and temporary land use agreements as both were previously approved by the OEB.

3.6 Indigenous Consultation

In accordance with the OEB's Environmental Guidelines, Enbridge Gas contacted the Ministry of Energy on June 29, 2021 with respect to the Crown's duty to consult related to the Project.[134] The Ministry of Energy, by way of a letter, delegated the procedural aspects of the Crown's Duty to Consult for the Project to Enbridge Gas on August 6, 2021 (Delegation Letter). In the Delegation Letter, the Ministry of Energy identified the following Indigenous communities that Enbridge Gas should consult in relation to the Project:

- Aamjiwnaang First Nation
- Bkejwanong (Walpole Island First Nation)
- Caldwell First Nation

[133] Enbridge Gas's application to access these lands is currently before the OEB (EB-2022-0285). It was originally filed on June 23, 2023. On August 25, 2023, Enbridge Gas asked that the application be placed in abeyance. The OEB granted the request. On December 8, 2023, Enbridge Gas asked that the OEB proceed with hearing its application.

[134] Enbridge Gas filed an updated application on June 16, 2023 reducing the scope of the Project by eliminating Leamington Interconnection component of the original Project and, amongst other things, updating the Indigenous consultation evidence.

- Chippewas of the Thames First Nation
- Chippewas of Kettle and Stony Point First Nation
- Oneida Nation of the Thames
- Delaware Nation[135]

Three Fires Group, an Indigenous business corporation, that jointly represents the interests of Chippewas of Kettle and Stony Point First Nation and Caldwell First Nation, has been actively participating in the proceeding as a registered intervenor. Enbridge Gas has engaged and consulted with the Three Fires Group members in the consultation process as delegated by the Ministry of Energy.

On June 10, 2022, Enbridge Gas provided to the Ministry of Energy the original Indigenous Consultation Report (ICR) for the Project. Enbridge Gas filed the ICR and supporting documents with the application's evidence. As part of the evidence, Enbridge Gas filed a summary of the Indigenous consultation activities up to June 7, 2022.[136] Enbridge Gas updated the engagement log, and the summaries of comments as of September 9, 2022. As of September 22, 2022, Enbridge Gas stated it was not aware of any outstanding issues and committed to continue to engage with the Indigenous communities.[137]

Shortly before filing the updated application, Enbridge Gas provided to the Ministry of Energy, on June 6, 2023 a description of the Project reflecting changes made to the Project scope. On June 16, 2023, on the date of the updated application filing, Enbridge Gas provided to the Ministry of Energy an updated ICR, which reflected a description of changes to the scope of the Project.[138] The Ministry of Energy confirmed that no changes to the direction provided in the Delegation Letter were required as a result of the Project update.

In accordance with the protocol set out in the OEB's Environmental Guidelines, the Ministry of Energy will review Enbridge Gas's updated ICR and its communication with potentially affected Indigenous groups and render its opinion on the adequacy of consultation by way of a letter to Enbridge Gas (Letter of Opinion). The Ministry of Energy conveyed to Enbridge Gas that it would issue the Letter of Opinion by the time that the record of the proceeding is closed (i.e., after reply argument).[139] Upon receipt of the Ministry of Energy's determination regarding the sufficiency of Indigenous

[135] In a follow-up email on August 6, 2021, the Ministry of Energy asked that Delaware Nation be included in the engagement and consultation on the Project.
[136] Exhibit H, Tab 1, Schedule 1, Attachment 6 and Attachment 7
[137] Enbridge Gas response to interrogatories I.STAFF.22 a)-d) and attachments 1-5, filed September 22, 2022
[138] Exhibit H, Tab 1, Schedule 1, page 2, paragraphs 5-6
[139] Enbridge Gas response to interrogatories I.STAFF.22 d) filed September 22, 2022

consultation on the Project, Enbridge Gas will file the Letter of Opinion with the OEB.

OEB Staff Submission

OEB staff is not aware of any outstanding concerns from Indigenous communities regarding any Aboriginal or treaty rights that may be impacted by the Project. OEB staff observes that Enbridge Gas has committed to ongoing communication and to address concerns raised by the Indigenous communities related to the Project. OEB staff notes that Three Fires Group, an intervenor in this proceeding, is representing the interests of Chippewas of Kettle and Stony Point First Nation and Caldwell First Nation and will have an opportunity to provide its written submission on these matters.

OEB staff notes that Enbridge Gas has informed the Ministry of Energy of updates to the Project, including providing the Ministry of Energy with updates to the ICR. OEB staff notes that the Ministry of Energy determined that no additional engagement activities due to the changes in Project scope were required.

OEB staff submits that Enbridge Gas appears to be cooperating with the Indigenous communities during the consultation process and that it made certain commitments to the Indigenous communities related to the Project.

If the OEB determines that it is appropriate to grant Leave to Construct for the Project, OEB staff submits that the OEB should wait to receive the Letter of Opinion from the Ministry of Energy before providing its final approval. If the Letter of Opinion is not filed prior to record close, the OEB can place the proceeding in abeyance until such time that the letter is filed.

OEB staff notes that, to the extent that the Letter of Opinion may identify outstanding issues, the OEB could elect to make provision for additional procedural steps to address these issues.

3.7 Conditions of Approval

Enbridge Gas stated that it has reviewed the OEB’s standard conditions of approval and has not identified any additional or revised conditions to propose for the Project.[140] In response to an OEB staff interrogatory, Enbridge Gas also accepted these standard conditions of approval.[141]

[140] Exhibit I, Tab 1, Schedule 1
[141] Enbridge Gas response to I.STAFF.23

OEB Staff Submission

OEB staff submits that the OEB should approve the Project subject to the Conditions of Approval attached as Schedule A to this submission.

As discussed previously, in the scenario that the OEB determines that CIAC payments should be required, given the potential that Enbridge Gas will need to re-evaluate the demand for the Project, OEB staff submits that it may be appropriate to extend certain timelines in the OEB's standard conditions of approval (e.g., 12-month termination of leave to construct approval, etc.).

~All of which is respectfully submitted~

Schedule A

Conditions of Approval

EB-2022-0157

December 14, 2023

Leave to Construct Application under
Section 90 of the OEB Act

Enbridge Gas Inc.
EB-2022-0157

Conditions of Approval

1. Enbridge Gas Inc. shall construct the facilities and restore the land in accordance with the OEB's Decision and Order in EB-2022-0157 and these Conditions of Approval.

2. (a) Authorization for leave to construct shall terminate 12 months after the decision is issued unless construction has commenced prior to that date.
   (b) Enbridge Gas Inc. shall give the OEB notice in writing:
      i. of the commencement of construction, at least 10 days prior to the date construction commences
      ii. of the planned in-service date, at least 10 days prior to the date the facilities go into service
      iii. of the date on which construction was completed, no later than 10 days following the completion of construction
      iv. of the in-service date, no later than 10 days after the facilities go into service

3. Enbridge Gas Inc. shall obtain all necessary approvals, permits, licences, certificates, agreements and rights required to construct, operate and maintain the Project.

4. Enbridge Gas Inc. shall implement all the recommendations of the Environmental Report filed in the proceeding, and all the recommendations and directives identified by the Ontario Pipeline Coordinating Committee review.

5. Enbridge Gas Inc. shall advise the OEB of any proposed change to OEB-approved construction or restoration procedures. Except in an emergency, Enbridge Gas Inc. shall not make any such change without prior notice to and written approval of the OEB. In the event of an emergency, the OEB shall be informed immediately after the fact.

6. Concurrent with the final monitoring report referred to in Condition 7(b), Enbridge Gas Inc. shall file a Post Construction Financial Report, which shall provide a variance analysis of project cost, schedule and scope compared to the estimates filed in this proceeding, including the extent to which the project contingency was utilized. Enbridge Gas Inc. shall also file a copy of the Post Construction Financial Report in the proceeding where the actual capital costs of the project are proposed to be included in rate base or any proceeding where Enbridge Gas Inc. proposes to

start collecting revenues associated with the Project, whichever is earlier.

7. Both during and after construction, Enbridge Gas Inc. shall monitor the impacts of construction, and shall file with the OEB one electronic (searchable PDF) version of each of the following reports:
   (a) A post construction report, within three months of the in-service date, which shall:
      i. provide a certification, by a senior executive of the company, of Enbridge Gas Inc.'s adherence to Condition 1
      ii. describe any impacts and outstanding concerns identified during construction
      iii. describe the actions taken or planned to be taken to prevent or mitigate any identified impacts of construction
      iv. include a log of all complaints received by Enbridge Gas Inc., including the date/time the complaint was received, a description of the complaint, any actions taken to address the complaint, the rationale for taking such actions
      v. provide a certification, by a senior executive of the company, that the company has obtained all other approvals, permits, licenses, and certificates required to construct, operate, and maintain the proposed project
   (b) A final monitoring report, no later than fifteen months after the in-service date, or, where the deadline falls between December 1 and May 31, the following June 1, which shall:
      i. provide a certification, by a senior executive of the company, of Enbridge Gas Inc.'s adherence to Condition 4
      ii. describe the condition of any rehabilitated land
      iii. describe the effectiveness of any actions taken to prevent or mitigate any identified impacts of construction
      iv. include the results of analyses and monitoring programs and any recommendations arising therefrom
      v. include a log of all complaints received by Enbridge Gas Inc., including the date/time the complaint was received; a description of the complaint; any actions taken to address the complaint; and the rationale for taking such actions

8. Enbridge Gas Inc. shall designate one of its employees as project manager who will be the point of contact for these conditions and shall provide the employee's name and contact information to the OEB and to all affected landowners and shall clearly post the project manager's contact information in a prominent place at the construction site.