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Enbridge Gas Inc.
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VIA EMAIL and RESS

October 3, 2023

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

Dear Nancy Marconi:

**Re: Enbridge Gas Inc. ("Enbridge Gas" or "the Company")
Ontario Energy Board ("OEB") File No. EB-2022-0157
Panhandle Regional Expansion Project ("Project")
Updated Interrogatory and Undertaking Responses**

On August 25, 2023, Enbridge Gas filed a letter with the OEB identifying a list of interrogatory and undertaking responses currently on the record in the above noted proceeding that are no longer applicable as a result of the Company's June 16, 2023 amended application. Further, Enbridge Gas identified a list of interrogatory and undertaking responses currently on the record that could be updated to reflect the Company's amended application. Accordingly, enclosed are updates to the following interrogatory and undertaking responses:

Exhibit	Update/New
I.STAFF.4	All responses listed have been updated to reflect amendments to the Company's application filed June 16, 2023. Amendments to the application are summarized at Exhibit A, Tab 4, Schedule 1.
I.STAFF.6	
I.STAFF.7	
I.STAFF.8	
I.STAFF.9	
I.STAFF.15	
I.STAFF.18	
I.STAFF.20	
I.STAFF.21	
I.APPrO.6	
I.ED.1	
I.ED.2	
I.ED.3	
I.ED.6	
I.ED.8	
I.ED.11	
I.ED.12	
I.ED.13	
I.ED.14	

I.ED.15	
I.EP.3	
I.EP.5	
I.EP.8	
I.EP.9	
I.FRPO.4	
I.FRPO.8	
I.PP.3	
I.PP.8	
I.PP.14	
I.PP.16	
I.PP.20	
I.PP.23	
I.TFG.2	
I.TFG.3	
I.TFG.5	
I.TFG.9	
JT1.4	
JT1.5	
JT1.15	
JT1.16	
JT1.18	
JT1.19	
JT1.21	
JT1.23	
JT1.32	
JT2.3	
JT2.7	
JT2.8	
JT2.9	
JT2.10	
JT2.11	
JT2.12	

Pursuant to the OEB's Practice Direction on Confidential Filings (the "Practice Direction"), Enbridge Gas hereby requests the confidential treatment of certain information contained in its updated interrogatory and undertaking responses. The confidential information has been redacted in the public version of the updated interrogatory and undertaking responses filed with the OEB. The requests for confidential treatment relate to two updated interrogatory responses. These interrogatory responses, as well as the reasons for requiring confidential treatment, are set out below.

Exhibit	**Confidential Information Location**	**Presumed Confidential**	**Basis for Claim**	**Rationale**
Exhibit JT1.21	Page 2	Yes	Information would disclose	The information consists of customer-specific, commercially sensitive,

Exhibit	**Confidential Information Location**	**Presumed Confidential**	**Basis for Claim**	**Rationale**
			energy usage information of a specific customer. Equivalent information previously held confidential by the OEB.	third-party information that reveals the nature and timing of third-party investment decisions. More particularly, the information concerns the timing and volume of incremental demand attributable to an individual customer, NextStar Energy. As further explained in the interrogatory response, additional information requires redaction to prevent the ability to back-calculate the information regarding the individual customer. The OEB considered and approved the confidential treatment of equivalent information in its December 1, 2022 decision on a motion by the Company in the current proceeding.
Exhibit JT1.23	Page 2	Yes	Information would disclose energy usage information of a specific customer. Equivalent information previously held confidential by the OEB.	The information consists of customer-specific, commercially sensitive, third-party information that reveals the nature and timing of third-party investment decisions. More particularly, the information concerns the timing and volume of incremental demand attributable to an individual customer, NextStar Energy. As further explained in the interrogatory response, additional information requires redaction to

Exhibit	Confidential Information Location	Presumed Confidential	Basis for Claim	Rationale
				prevent the ability to back-calculate the information regarding the individual customer. The OEB considered and approved the confidential treatment of equivalent information in its December 1, 2022 decision on a motion by the Company in the current proceeding.

Unredacted, confidential copies of the interrogatory responses will be sent separately via email to the OEB.

Consistent with the Practice Direction, it is the Company's expectation that access to confidential information in this proceeding will only be available to representatives of parties that file Declarations and Undertakings in the prescribed form.

The above noted submission has been filed electronically through the OEB's RESS and will be made available on Enbridge Gas's website.

If you have any questions, please contact the undersigned.

Sincerely,

(Original Signed)

Haris Ginis
Technical Manager, Leave to Construct Applications

ENBRIDGE GAS INC.

Answer to Interrogatory from
The Association of Power Producers of Ontario ("APPrO")

INTERROGATORY

References:

Exhibit B, Tab 1, Schedule 1, Page 7 of 19
Exhibit B, Tab 2, Schedule 1, Page 9 of 16

Preamble:

"There are additional industrial customers requesting Panhandle System capacity, but which were not part of the EOI process. These additional customers are not currently included in the demand forecast for the Project due to the preliminary nature of their requests, but their requests provide further support for the growing need for capacity on the Panhandle System."

"The general service (Rate M1 and Rate M2) demand consists of residential, commercial, and small industrial customers. Approximately 45% of the firm demand served by the Panhandle System is for the general service customers.

The contract rate (M/BT4, M/BT5, M/BT7, T-1 and T-2) demand accounts for about 55% of the firm demand served by the Panhandle System. The contract rate demand consists of power generation, greenhouse and large commercial/industrial. The current mix is 29% power generation, 52% greenhouse and 19% large commercial/industrial customers."

Question:

a) Please provide a high-level estimate of the potential demand that is not included in this application, but may materialize over the next decade.
b) Please provide the additional capacity that may be required based on preliminary requests that were not included in Enbridge's current forecast for the Panhandle system.
c) What will the future split be between the "System General Service Market" and "System Firm Contract Market" with: (i) current forecasts; and (ii) the potential demand that is not included in the application over the next decade?

d) What will the future demand mix be with: (i) current forecasts; and (ii) the potential demand that is not included in the application over the next decade?

Response

a) and b)
Enbridge Gas is aware of an increased demand for natural gas in the Panhandle Market via local economic development organizations and recent publications: /U

- March 2023: “Drawings, details of new hospital revealed during virtual town hall” – https://windsorstar.com/news/local-news/drawings-details-of-new-hospital-revealed-during-virtual-town-hall
- April 2023: “Windsor-Essex being eyed for billions in new industrial investment” – https://windsorstar.com/news/Windsor-essex-being-eyed-for-billions-in-new-industrial-investment
- June 2023: “New Interchange Connecting Lauzon Parkway To 401 'Highest Priority' Says Ford” – https://www.iheartradio.ca/am800/news/new-interchange-connecting-lauzon-parkway-to-401-highest-priority-says-ford-1.19736147
- July 2023: “Windsor lands another big EV auto supply chain company” – https://windsorstar.com/news/Windsor-lands-another-big-ev-auto-supply-chain-company
- August 2023: “Windsor inching closer to landing another major foreign investment” – https://windsorstar.com/news/Windsor-inching-closer-to-landing-another-major-foreign-investment

Please also see a recent Globe and Mail article which includes commentary from the greenhouse industry:

- August 2023: “Southern Ontario’s greenhouse operators warn lack of infrastructure is slowing growth in booming sector” – https://www.theglobeandmail.com/business/article-windsor-greenhouse-growers-infrastructure/

c)

i) By Winter 2030/2031, General Service demands are estimated to account for 35% of the total firm Panhandle System Market, and Firm Contract demands are estimated to account for 65% of the total firm Panhandle System Market. /U

ii) By Winter 2033/2034, General Service demands are estimated to account for 34% of the total firm Panhandle System Market, and Firm Contract demands are estimated to account for 66% of the total firm Panhandle System Market.

d)

i) By Winter 2030/2031, the breakdown of firm contract demands excluding general service is estimated to be: /U

- Power Generation: 32%
- Greenhouse: 56%
- Large Commercial/Industrial: 12%

ii) By Winter 2033/2034, the breakdown of firm contract demands excluding general service is estimated to be:

- Power Generation: 31%
- Greenhouse: 58%
- Large Commercial/Industrial: 11%

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Ex. B, Tab 1, Schedule 1.

Question:

(a) Please provide a copy of table 1 on page 11 with the figures converted to m3/d.
(b) Please provide conversation factors for TJ to m3.
(c) On page 14, Enbridge states: "The greenhouse sector does not currently have a viable economic alternative to replace natural gas for heat and CO_2 production." Please provide an analysis comparing the cost of heating a greenhouse with gas versus a high-efficiency heat pump. Please provide this analysis over a 15 year time horizon, including the federal government's planned increases to the carbon price.

Response

a) Please see Table 1.

Table 1

	Historical Actuals (m3/d)			FORECAST (m3/d)									/U
	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**	
General Service Firm (Total)	8,137,763	7,853,310	7,884,028	7,832,260	7,880,854	7,928,707	7,974,872	8,019,785	8,062,781	8,104,141	8,143,482	8,180,905	
Contract Firm (Total excluding Power Generators)	5,591,970	6,144,934	6,500,153	7,309,867	8,082,515	8,408,921	8,735,302	9,061,708	9,388,113	9,714,519	10,040,900	10,367,306	
Power Generators - Firm Contract only	2,697,871	2,706,441	2,700,102	2,701,022	2,701,022	4,168,021	4,987,398	4,987,398	4,987,398	4,987,398	4,987,398	4,987,398	
Total System Demand Forecast	16,427,604	16,704,684	17,084,283	17,843,149	18,664,392	20,505,649	21,697,572	22,068,891	22,438,292	22,806,058	23,171,779	23,535,608	
General Service Firm (Total Incremental Demand)	486,326	(222,301)	38,708	(92,076)	48,594	47,853	46,166	44,913	42,996	41,360	39,340	37,423	
Contract Firm (Incremental excluding Power Generators)	627,860	595,672	361,470	776,483	772,648	326,406	326,380	326,406	326,406	326,406	326,380	326,406	
Power Generators - Firm Contract only (incremental)	(565,777)	29,175	(3,586)	(12,883)	-	1,466,999	819,376	-	-	-	-	-	
Total Incremental Demand Forecast	548,409	402,546	396,592	671,524	821,242	1,841,258	1,191,922	371,319	369,402	367,766	365,721	363,829	
Total Incremental Demand Forecast (Cumulative)	-			671,524	1,492,766	3,334,024	4,525,946	4,897,265	5,266,667	5,634,433	6,000,153	6,363,983	

b) The conversion factor from TJ per day to m^3 per day is based on the System Wide Average Heating Value ("SWAHV") which is updated annually. The conversions are as follows: /U
   - For Winter 2019/2020: 0.00003898 TJ/m^3
   - For Winter 2020/2021: 0.00003928 TJ/m^3
   - For Winter 2021/2022: 0.00003932 TJ/m^3
   - For Winter 2022/2023 to W2030/2031: 0.00003912 TJ/m^3

c) Enbridge Gas has not developed an analysis comparing the cost of heating a greenhouse with natural gas versus an electric heat pump. The reference to the viability of alternative solutions for heating and CO_2 production for greenhouses is based on the utility's understanding of greenhouse operations, as well as greenhouse customer requirements for natural gas via the EOI process. Enbridge Gas is not aware of any large greenhouse customers that use electric heat pumps for heating and CO_2 production.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Ex. B, Tab 1, Schedule 1.

Preamble:

Enbridge states as follows on page 9: "Approximately 45% of the firm demand served by the Panhandle System is for general service customers. Enbridge Gas forecasts that general service customer demand in the Panhandle Market will increase by approximately 3.7% between winter 2021/2022 and 2030/2031. Incremental demands from general service customers make up approximately 2.5% of the incremental capacity of the proposed Project."

Question:

(a) Please provide a table listing the forecast number of general service customers, broken down by customer type, and showing the per-customer average demand for each customer type, for 2021/2022 and 2030/2031, for the relevant area.
(b) Please provide the customer attachment forecast for the 2021/2022 and 2030/2031, including a breakdown by customer type and a breakdown by new construction versus conversion of existing building

Response

a) and b)
Please see Table 1 below.

Table 1: Forecast General Service Attachments, Panhandle Market (2022-2031)

Year	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential Attachments	1,487	1,473	1,454	1,424	1,394	1,333	1,277	1,221	1,158
Commercial Attachments	106	117	115	112	109	105	101	98	94
Industrial Attachments	3	3	3	2	2	2	2	1	1

The number of general services customers in the relevant area is estimated to be approximately:

- Residential: 180,500
- Commercial/Industrial: 15,500

The per-customer average demand for each customer attachment type is assumed to be 0.89 m^3/hr and 9.72 m^3/hr for commercial/industrial.

The general service attachments on the Panhandle System is assumed to be approximately 1-5% fuel conversions.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Ex. B, Tab 1, Schedule 1.

Preamble:

On page 15, Enbridge states: "As noted in the IESO's December 2021 Annual Planning Outlook, the Brighton Beach Generating Station ("BBGS") will play a particularly critical role in meeting localized power generation needs between 2024 and 2028.[11] With demand for electricity continuing to grow, it is expected that the BBGS will continue to play a significant role in meeting the region's electricity supply needs beyond 2028. It is Enbridge Gas's understanding that these near-term and longer-term needs have driven the request for incremental firm service from this customer."

Question:

(a) Please reproduce the table 1 on page 11 with an additional row to indicate the historical and forecast design day demand attributable to power generation.
(b) Seeing as Ontario is a summer peaking jurisdiction, please explain how Enbridge determines the design day demand associated with power generation.
(c) Please provide the actual demand from power generation on the three highest demand days in each of the last ten years for the project area.
(d) Please provide the design day demand from power generation for the last ten years as assumed in Enbridge's gas supply planning processes.

Response

a) Please see Exhibit B, Tab 1, Schedule 1, Table 2. /U

b) Design day demand for power generators is equivalent to their firm contract demand. Power generators can exercise their contract at any time and this capacity is held to be dispatchable when it is called upon. Enbridge Gas must plan to meet all contractual obligations and must plan to meet these requirements on the design day. /U

c) Please see Table 2 below.

Table 2: Natural Gas-fired Power Generation on the Three Highest Demand Days

Year	Date	Power Generation Demand (10^3m^3/day)
2022	20-Jan-2022	2311
2022	21-Jan-2022	1549
2022	14-Feb-2022	1774
2021	5-Feb-2021	11
2021	15-Feb-2021	7
2021	16-Feb-2021	14
2020	13-Feb-2020	64
2020	26-Feb-2020	44
2020	27-Feb-2020	48
2019	29-Jan-2019	654
2019	30-Jan-2019	684
2019	31-Jan-2019	1492
2018	04-Jan-2018	1258
2018	05-Jan-2018	1563
2018	16-Jan-2018	1545
2017	6-Jan-2017	1639
2017	7-Jan-2017	302
2017	13-Mar-2017	69
2016	4-Jan-2016	2198
2016	17-Jan-2016	1112
2016	18-Jan-2016	1128
2015	19-Feb-2015	3215
2015	20-Feb-2015	3578
2015	23-Feb-2015	3172
2014	21-Jan-2014	4261
2014	22-Jan-2014	4241
2014	11-Feb-2014	4114
2013	21-Jan-2013	1854
2013	22-Jan-2013	3229
2013	23-Jan-2013	2822

d) As outlined in Exhibit I.ED.4 part b), the design day demand forecast in the Gas Supply Plan is shown by rate zone and not by individual transmission pipeline system. Table 3 below shows the design day demand for the power generation customers served by the Panhandle System from Winter 2012/2013 to Winter 2021/2022.

Table 3: Power Generation Design Day Demand

	Design Day Demands (TJ/d)									
	Winter 12/13	**Winter 13/14**	**Winter 14/15**	**Winter 15/16**	**Winter 16/17**	**Winter 17/18**	**Winter 18/19**	**Winter 19/20**	**Winter 20/21**	**Winter 21/22**
Power Generators - Firm Only (TJ/d)	108	108	129	130	131	131	127	105	106	106

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1

Question:

(a) Please reproduce table 1 on page 11 of Ex. B, Tab 1, Schedule 1, adding rows with the following additional information:
   i. The potential capacity that could be feasibly sourced from Ojibway, in terms of the TJ/d at Ojibway and the TJ/d at the Leamington-Kingsville area;
   ii. The potential capacity that could be cost-effectively sourced from Ojibway, in terms of the TJ/d at Ojibway and the TJ/d at the Leamington-Kingsville area;
   iii. The potential capacity that could be obtained through targeted cost-effective energy efficiency programming;
   iv. The potential capacity that could be obtained via demand response contracts (i.e. incenting customers to switch to interruptible service); and
   v. The forecast demand from power generation.

(b) Please provide a table showing the annual cost for items (i) to (iv) above.

Response

a)

i. Enbridge Gas interprets "feasibly sourced" to mean what is currently available on the Panhandle Eastern System. This is estimated to be 21 TJ/d of incremental supply. /U

Table 1 includes the requested information:

- The estimated base system capacity if an incremental 21 TJ/d was available at Ojibway and the gas was consumed in Leamington/Kingsville; and
- The estimated base system capacity if an incremental 21 TJ/d was available at Ojibway and the gas was consumed in Windsor near Ojibway.

The estimated capacity has been updated based on the refiled evidence forecast and timing.

Table 1: System Capacity with Additional Ojibway Supply

	Historical Actuals			FORECAST									
	W19/20	W 20/21	W 21/22	W 22/23	W 23/24	W 24/25	W 25/26	W 26/27	W 27/28	W 28/29	W 29/30	W 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)	84	69	41	38	6	(66)	(112)	(127)	(141)	(156)	(170)	(184)
Panhandle System Capacity with 21 TJ/d incremental Ojibway Supply measured in Leamington / Kingsville				737	737	746	746	746	746	746	746	746
Panhandle System Capacity with 21 TJ/d incremental Ojibway Supply measured at Ojibway				737	737	758	758	758	758	758	758	758

ii. There is no Panhandle System capacity that could be cost-effectively sourced from Ojibway compared to the proposed Project. This alternative was evaluated and deemed a non-viable alternative. Please see the response to Exhibit I.STAFF.7, Attachment 2.

iii. Enbridge Gas reviewed potential capacity that could be obtained through targeted cost-effective energy efficiency programming and determined that a maximum peak hour reduction potential of 72,000 m^3/hour (57 TJ/d) could be obtained. For additional details please refer to Exhibit C, Tab 1, Schedule 1, Pages 20-21, Paragraph 67, and the response at Exhibit I.STAFF.7, Attachment 2. /U

iv. There is no potential capacity that could be obtained via demand response. Please see the response at Exhibit I.STAFF.9, part b).

v. Please see the response to Exhibit I.ED.3, part a).

b) Please see Table 2 below. /U

Table 2: Costs of Additional Capacity and ETEE

Item #	Potential Panhandle System Capacity Source	Estimated Costs
i, ii	21 TJ/d Firm Exchange between Dawn and Ojibway	$4.2 million Annually
iii	57 TJ/d Enhanced Targeted Energy Efficiency (ETEE)	~$468 million Total

Please also see the response to Exhibit I.STAFF.7, Attachment 2.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit E, Tab 1, Schedule 5

Question:

(a) Please provide the DCF analysis in a live excel format.
(b) Please re-calculate the project NPV and PI based on there being zero revenue attributable to the expansion project (i) from 2035 onward, (ii) from 2040 onward, and (iii) from 2050 onward. We are not asking Enbridge to opine on these figures as if they are likely scenarios.
(c) If the project is built but demand does not increase above the current capacity of 713 TJ/d, does Enbridge agree that there would be no incremental revenue attributable to the project? If Enbridge disagrees, please explain.
(d) If the project is built, demand initially increases beyond 713 TJ/d, but then declines to below 713 TJ/d from 2035 onward, does Enbridge agree that there would be no incremental revenue attributable to the project from 2035? If Enbridge disagrees, please explain.
(e) In light of federal decarbonization mandates, what is the probability that the design day demand of the panhandle system is at or below 713 TJ/d in (i) 2035, (ii) 2040, or (iii) 2050. Please provide an answer on a best estimate basis.

Response

a) Please see Attachment 1.

b) See Table 1 below. /U

Table 1: Project NPV and PI Based on Zero Revenue from 2035, 2040, and 2050 Onwards

Scenario		NPV ($million)	PI
i	2035 onward	(202)	0.30
ii	2040 onward	(186)	0.35
iii	2050 onward	(165)	0.43

c) and d)
Enbridge Gas agrees that incremental revenue is tied to incremental demands.

However, as set out in Exhibit B, Tab 1, Schedule 1, the needs for the Project were determined by demands reported by customers through the EOI process. As such, the Company has no basis to expect system demands will decline in the manner suggested by ED.

e) ED's question seeks to have the Company create new evidence based on hypothetical scenarios that would see demand for natural gas decline significantly from current levels. It is not reasonably possible to produce the forecast sought by ED with any certainty as it is unclear how and when the Federal Guidelines will be implemented in Ontario, and what the rate of adoption and/or conversion to alternative energy sources will ultimately be.

Not only does Enbridge Gas not routinely produce forecasts for the durations sought by ED (in part due to escalating forecast uncertainty that is increasingly inherent in longer term forecasts), but it is not practically possible for the Company to completely re-assess the hydraulic models, demand forecasting methodology, engineering design principles, and other factors that currently guide its assessment of projects as part of a response to interrogatories in the current proceeding.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit E, Tab 1, Schedule 1

Question:

(a) Please reproduce table 1 on page 11 of Ex. B, Tab 1, Schedule 1, adding rows showing:
   i. A breakdown of the demand based on customer classes (residential, commercial, and industrial); and
   ii. A breakdown of demand for forecast years based on that from new versus existing customers.

   Please also add three columns to the left with three additional years of historical figures.

Response

a)

i. Below is the summary of demand breakdown by the customer classes indicated (residential, commercial, and industrial) using best available information. /U

ii. There is no forecast demand change for existing general service customers.

	Historical Actuals (TJ/d)						FORECAST (TJ/d)								
	Winter 16/17	**Winter 17/18**	**Winter 18/19**	**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**
General Service Firm (Total System Demand)	298	291	298	317	308	310	306	308	310	312	314	315	317	319	320
Residential Demand (M1)	158	157	163	171	166	167	171	164	165	167	169	169	170	170	169
Commercial/Industrial (estimated M1/M2)	140	134	135	146	142	143	135	144	145	145	145	146	147	149	151
Contract Firm (Total System Demand)	259	321	326	323	348	362	392	422	492	537	550	562	575	588	601
Total System Demand Forecast	**557**	**612**	**624**	**640**	**656**	**672**	**698**	**730**	**802**	**849**	**863**	**878**	**892**	**906**	**921**

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit E, Tab 1, Schedule 1

Question:

(a) What is the expected lifetime of the proposed pipeline?
(b) When would the proposed pipeline be fully depreciated?
(c) What will the undepreciated balance of the proposed pipeline costs be in (i) 2035, (ii) 2040, and (iii) 2050?
(d) Has Enbridge conducted an analysis to assess the likelihood, if any, that the proposed pipeline will be stranded or underutilized before the end of its lifetime? If yes, please file said analysis.
(e) Please estimate the probability (if any) that the proposed pipeline will be stranded or underutilized before the end of its lifetime. Please provide the response as a probability (%) or a range of probabilities. For instance, if there is no chance, please indicate the probability as 0%.

Response

a) The current OEB-approved depreciation rate for transmission pipelines in the Union Rate Zone assumes an economic life of 55 years.

b) Assuming current OEB-approved depreciation rates, the proposed pipeline will be fully depreciated in 2075. /U

c) The undepreciated balance of the proposed pipeline(s) is: /U
   i. in 2035 = $146 million
   ii. in 2040 = $128 million
   iii. in 2050 = $91 million

d) and e)

No, the proposed Project is based on best available demand forecasts, customer commitments, and is designed to reliably serve known increased demands for firm service in the Panhandle Market, including, in particular, incremental demands from the greenhouse, automotive, and power generation sectors. The Company has no basis to believe the proposed pipeline will be undersubscribed or stranded.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit E, Tab 1, Schedule 1

Question:

(a) How many cubic metres of gas is associated with the incremental revenue included in the stage 1 DCF calculations?
(b) How many tonnes of carbon emissions will be emitted due to the combustion of those m3s of gas?
(c) Does Enbridge believe that carbon emissions are a public interest consideration relevant to stage 3 of the test?

Response

a) Approximately 18.5 billion m^3. /U

b) The greenhouse gas ("GHG") emissions emitted due to the combustion of the natural gas volumes provided in part a) above are approximately 36 million tonnes of carbon dioxide equivalent ("tCO_2e"). Enbridge Gas notes that approximately half of the gas will be delivered to greenhouse customers, and as such a portion of these emissions will be sequestered within plants. /U

c) Enbridge Gas believes carbon emissions are relevant to stage 2 of the Project economics.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit E, Tab 1, Schedule 6

Question:

(a) Please provide all spreadsheets and detailed calculations underlying Exhibit E, Tab 1, Schedule 6. Please include live excel spreadsheets.
(b) Please provide Enbridge's best forecast of gas prices starting at the in-service date for (i) 20 years and (ii) 40 years.
(c) Please approach the gas supply group and the DSM group and ask them to provide their best forecast of gas prices.
(d) Please provide ICF's latest annual gas price forecast. As this is proprietary, this can be provided confidentially. Please also provide the forecast as percent increases and apply those values to the prices in the relevant area.
(e) Please describe how Enbridge generated its electricity price, including underlying calculations.
(f) Please provide Enbridge's best forecast of electricity prices starting at the in-service date for (i) 20 years and (ii) 40 years.
(g) Please justify the assumption that the carbon tax will remain at $170 from 2031 to 2063. How confident is Enbridge in this prediction?
(h) Please confirm that Enbridge estimated the cost of electric heating on the assumption that resistance heating is used, not a high efficiency heat pump.
(i) Please describe the methodology used to generate Exhibit E, Tab 1, Schedule 6. Please also how this meets the requirements in E.B.O. 134 with specific references to the relevant sections of E.B.O. 134.
(j) Please confirm whether Enbridge used customer-facing prices or avoided costs in this analysis. Please provide Enbridge's understanding of what E.B.O. 134 requires in this regard.
(k) Please confirm that in the stage 2 analysis in EB-2016-0186 (Panhandle Reinforcement Project), which was filed in June if 2016, Union Gas used the following assumption: "Gas and alternative fuel prices are the average posted prices for the 12 month period June 2015 to May 2016."

Response

a) Please see Attachment 1.

b) - d)
Please see the response at Exhibit I.PP.11. Enbridge Gas is not able to produce the forecast information sought by ED at this time.

e) Enbridge Gas generated its electricity pricing based upon the posted electricity pricing from the Ontario Energy Board website for the 12 months ending March 2023.[1] The posted pricing was converted from a cents per kilowatt hour to a dollar per gigajoule. The dollar per gigajoule was then converted to a dollar per m^3 assuming a heat content of 0.03932 GJ per m^3. Please see Attachment 2 to this response for the supporting calculation. /U

f) Enbridge Gas is not able to produce the forecast information sought by ED at this time. Electricity prices can be found at the IESO website, and any questions regarding electricity prices are more appropriately directed to the IESO: https://www.ieso.ca/en/Power-Data/Monthly-Market-Report

g) To date, the Government of Canada has only announced the annual carbon price to 2030; however, the updated pricing has not been included in the Greenhouse Gas Pollution Pricing Act. Further, the Government of Canada has not provided any indication if carbon pricing will continue in 2031 or beyond, or at what rates. Absent this information, Enbridge Gas has assumed that carbon pricing will continue beyond 2030 remaining at a cost of $170 per tonne.

h) The Stage 2 analysis does not consist of an explicit variable related to the type of end-use equipment, for any fuel types. Enbridge Gas does not believe E.B.O. 134 identifies a specific requirement in this regard. Please see parts a) and e) above for more information on the methodology employed.

i) The Stage 2 analysis determines the net present value of the difference in energy prices of alternative energy sources (heating oil, propane, electricity) versus natural gas. The price difference is applied to the forecast natural gas energy that the Project will provide to future general service customers. This aligns with E.B.O. 134 paragraph 6.74 which states:

[1] https://www.oeb.ca/consumer-information-and-protection/electricity-rates/historical-electricity-rates

> The second stage should be designed to quantify other public interest factors not considered at stage one. All quantifiable other public interest information as to costs and benefits should be provided at the stage.[2]

This methodology has been accepted by the OEB in numerous past applications. For details on the methodology used to develop Exhibit E, Tab 1, Schedule 6, please refer to part a) above.

j) Enbridge Gas used retail costs in this analysis (please see the response to Exhibit I.STAFF.15 c) part iii). Enbridge Gas does not believe that E.B.O. 134 identifies a specific requirement in this regard.

k) Confirmed.

[2] Ontario Energy Board, E.B.O. 134 Report of the Board, June 1, 1987, paragraph 6.74

	OEB Posted Rate (cents / kWh)				$ / GJ			
Date	Off-peak	Mid-peak	On-peak	kWh to GJ Conversion	Off-peak	Mid-peak	On-peak	Weighted Average
Feb 8, 2022	8.2	11.3	17.0	0.36	22.78	31.39	47.22	28.68
Nov 1, 2022	7.4	10.2	15.1		20.56	28.33	41.94	25.76

Date	Price ($/GJ)
Apr 2022	28.68
May 2022	28.68
Jun 2022	28.68
Jul 2022	28.68
Aug 2022	28.68
Sep 2022	28.68
Oct 2022	28.68
Nov 2022	25.76
Dec 2022	25.76
Jan 2023	25.76
Feb 2023	25.76
Mar 2023	25.76
Average	**27.47**
GJ to m3 conversion	0.03932
Electricity Price ($/m3)	**$ 1.080**

ENBRIDGE GAS INC.

Answer to Interrogatory from
Environmental Defence ("ED")

INTERROGATORY

Reference:

Exhibit E, Tab 1, Schedule 6

Question:

(a) Please recalculate Exhibit E, Tab 1, Schedule 6 with the following assumptions and provide both the output (i.e. Schedule 6) and the underlying excel spreadsheet:
   i. Gas and alternative fuel prices are the average posted prices for the most recent 12 month period; and
   ii. Use of electricity is on average three times as efficient as the use of gas (e.g. cold climate heat pump versus gas furnace).

(b) Please recalculate Exhibit E, Tab 1, Schedule 6 with the following assumptions and provide both the output (i.e. Schedule 6) and the underlying excel spreadsheet:
   i. Gas and alternative fuel prices are the average posted prices for the most recent 12 month period;
   ii. Use of electricity is on average three times as efficient as the use of gas (e.g. cold climate heat pump versus gas furnace); and
   iii. Carbon prices increase by $15/tonne to 2035 and increase with inflation thereafter.

Response

a) Please see Attachment 1 to this response for the Stage 2 results using the average posted prices for the 12 months ending August 2023. Please see Attachment 2 to this response for the underlying excel spreadsheet. /U

b) Please see Attachment 3 to this response for the Stage 2 results using the average posted prices for the 12 months ending August 2023 and the increasing carbon pricing scenario requested by ED. Please see Attachment 4 for the underlying excel spreadsheet. /U

Stage 2 (Customer Fuel Savings) Data for Panhandle Regional Expansion Project

Assumptions

(a)	(b)	(c)	(d)=(b)-(c)
Fuel Prices	$/m^3	Gas $/m^3	Diff $/m^3
Heating Oil	1.64	0.20	1.43
Propane	1.14	0.20	0.93
Electricity	1.11	0.20	0.91

Fuel Mix in the Event Gas is Not Available

	(e)	(f)=(d)*(e)
	General Service	
	Fuel Mix	Wt Ave Diff $/ M^3
Heating Oil	24%	0.342
Propane	10%	0.089
Electricity	67%	0.604
Total %	100%	
Weighted Savings $/m^3		1.035

Gas and alternative fuel prices are the average posted prices for the 12 month period ending August 2022
Prices in the table are before the added cost of Carbon.

Carbon Prices The cost of carbon is added to the price of each fuel excluding electricity.

	2023	2024	2025	2026	2027	2028	2029	2030
Cost per tonne	$65	$80	$95	$110	$125	$140	$155	$170

	Future Yrs 2031 and beyond
Cost per tonne	$170

Calculation for Stage 2 Incremental Energy Demand

	Estimated Energy Demand with Pipeline Built
Equals	Potential annual energy demand (for Stage 2 calculations)
Times	Weighted Average Savings per M3 plus Cost of Carbon
Equals	Annual Fuel Savings: Natural Gas Vs Alt Fuels

Discount Rate for Net Present Values 4.0%

Length of Term for Fuel Savings
Stage 2 estimated based on 20 years and 40 years

Present Value of Customer Fuel Savings
For conservatism, the NPV is assessed over 20 years with sensitivity at 40 years

Figures in $ Millions	20 Years	40 Years
General Service Fuel Savings	234	366

NPV Fuel Savings Range from $234 Mil over 20 yrs to $366 Mil over 40 yrs

Stage 2 (Customer Fuel Savings) Data for Panhandle Regional Expansion Project

Assumptions

(a)	(b)	(c)	(d)=(b)-(c)
Fuel Prices	$/m^3	Gas $/m^3	Diff $/m^3
Heating Oil	1.64	0.20	1.43
Propane	1.14	0.20	0.93
Electricity	1.11	0.20	0.91

Fuel Mix in the Event Gas is Not Available

	(e)	(f)=(d)*(e)
	General Service	
	Fuel Mix	Wt Ave Diff $/ M^3
Heating Oil	24%	0.342
Propane	10%	0.089
Electricity	67%	0.604
Total %	100%	
Weighted Savings $/m^3		1.035

Gas and alternative fuel prices are the average posted prices for the 12 month period ending August 2022
Prices in the table are before the added cost of Carbon.

Carbon Prices The cost of carbon is added to the price of each fuel excluding electricity.

	2023	2024	2025	2026	2027	2028	2029	2030
Cost per tonne	$65	$80	$95	$110	$125	$140	$155	$170
	2031	2032	2033	2034	2035	Future Yrs 2036 and beyond		
Cost per tonne	$185	$200	$215	$230	$245	increases annually by 2% inflation		

Calculation for Stage 2 Incremental Energy Demand

	Estimated Energy Demand with Pipeline Built
Equals	Potential annual energy demand (for Stage 2 calculations)
Times	Weighted Average Savings per M3 plus Cost of Carbon
Equals	Annual Fuel Savings: Natural Gas Vs Alt Fuels

Discount Rate for Net Present Values 4.0%

Length of Term for Fuel Savings
Stage 2 estimated based on 20 years and 40 years

Present Value of Customer Fuel Savings
For conservatism, the NPV is assessed over 20 years with sensitivity at 40 years

Figures in $ Millions	20 Years	40 Years
General Service Fuel Savings	222	326

NPV Fuel Savings Range from $222 Mil over 20 yrs to $326 Mil over 40 yrs

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 1, page 11, paragraph 31, Table 1

Question:

What percentage of the increase in the demand day forecast is due to contract firm customers?

Response

Please see Table 1. /U

Table 1

	FORECAST (TJ/d)								
	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
General Service Firm (Total Incremental Demand)	-4	2	2	2	2	2	2	2	1
Contract Firm (Incremental excluding Power Generators)	30	30	70	45	13	13	13	13	13
Total Incremental Demand Forecast	**26**	**32**	**72**	**47**	**15**	**14**	**14**	**14**	**14**
Percent contract of Incremental Demand (%)	**114.3%**	**94.1%**	**97.4%**	**96.1%**	**87.9%**	**88.4%**	**88.8%**	**89.2%**	**89.7%**

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, page 4

Preamble:

"Ex-franchise easterly C1 Rate transportation and Interruptible in-franchise contract rate demands are not included in the Design Day demand as they are not controlled by Enbridge Gas and are not guaranteed to arrive on Design Day."

Question:

a) Please explain what is ex-franchise easterly C1 Rate transportation contract rate demand?

b) Is there in-franchise easterly C1 Rate transportation contract rate demand? If the answer is yes, what is the amount, and has it been included in the Design Day demand?

c) Who controls easterly C1 Rate transportation contract demand?

Response

a) The Enbridge Gas C1 Transportation service provides a reliable, cost-effective means to move gas from any one point on the Enbridge Gas transmission system to another. C1 Transportation service also allows for the movement of gas to and from interconnecting pipelines.

   The Enbridge Gas Panhandle System interconnects with the Panhandle Eastern Pipeline Company ("PEPL") system at Ojibway. Therefore, the Enbridge Gas Panhandle System provides C1 Transportation service between Dawn and Ojibway.

There is currently one C1 Rate ex-franchise customer of Enbridge Gas, with a firm transportation contract of up to 37 TJ/d, to transport natural gas easterly from Ojibway to Dawn on a year-round basis. There are currently no C1 ex-franchise customers with C1 service westerly from Dawn to Ojibway.

b) No, C1 Transportation is a service designed for use by ex-franchise customers. In-franchise customers pay for their use of the Panhandle System within in-franchise service rates.

c) Ex-franchise C1 transportation service customers control easterly C1 rate transportation contract demand. C1 transportation is a non-obligated service meaning customers have the exclusive option to nominate quantities under the contract when needed. As a result, Enbridge Gas cannot rely on natural gas transported under C1 rate contracts to be delivered to Ojibway on a daily basis. Ex-franchise C1 transportation from Ojibway to Dawn can be limited by three factors: i) the quantity of capacity held by Enbridge Gas; ii) the capacity of the upstream pipeline system connected to Ojibway; and iii) the physical Panhandle System assets and the minimum Panhandle Market available to consume gas between Ojibway and Dawn as discussed at Exhibit B, Tab 2, Schedule 1, Pages 7-9. /U

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit C, Tab 1, Schedule 1, page 11, Table 3, Pipeline Loop, and Lateral Interconnect Economic Assessment

Question:

a) Please confirm that the alternative with the least negative NPV would require the least subsidy from ratepayers over its life.

b) Please confirm that the NPS 30 line with the NPS 16 lateral has the least negative NPV and would require a lower subsidy than the preferred alternative.

Response

a) & b) /U

The differences in NPV between the NPS 36 and NPS 30 alternatives are primarily attributable to total capital and annual property taxes. However, in Enbridge Gas's experience, NPV results alone should not be the sole contributing factor in selecting a preferred alternative.

In this instance in particular, there are at least three other critically important factors that the OEB must consider in selecting between the NPS 36 and NPS 30 pipelines:

i. **Future System Capacity Benefit -** As discussed in Exhibit B, Tab 1, Schedule 1, the Panhandle System has experienced significant demand growth in recent history, in part due to the rapid expansion of the greenhouse market, increasing in size from approximately 1,500 acres in 2007 to over 3,500 acres in 2022.[1] To serve such growth, the Panhandle System has

[1] https://www.ogvg.com/post/ogvg-applauds-the-province-for-supporting-economic-development-in-southwestern-ontario

expanded in 2013, 2016, 2017, and 2019. This growth trend is anticipated to continue based on the results of the EOI and planned expansion of the Automotive and Power Sectors in the region in order to meet growing demands for electric vehicles.

The proposed Project provides current and future system capacity benefits and thus positions the Panhandle System to provide cost-effective capacity to meet the long-term needs summarized above. More specifically, the NPS 36 Panhandle Loop provides the best long-term solution to alleviate the NPS 20 bottleneck between Dover Transmission and Comber Transmission stations as the NPS 36 loop is extended to Comber Transmission. The NPS 36 alternative provides an additional 8 TJ/d of capacity in the short-term when compared to the NPS 30 alternative. Please note, the full potential increase in capacity that could be created by the NPS 36 is limited at this time by the existing downstream bottlenecks. As future demand growth and associated reinforcement continues to occur and as bottlenecks are alleviated, the NPS 36 alternative provides an additional 28 to 117 TJ/d of incremental capacity compared to the NPS 30 alternative.

ii. **Cost Per Unit of Capacity -** The proposed Project is more cost effective than the NPS 30 alternative because it creates an additional 8 TJ/d of capacity in comparison (168 TJ/d vs 160 TJ/d)[2] and results in a lower cost per unit of capacity ($2.13/TJ vs $2.14/TJ).[3] This additional capacity is critical when considering how best to serve the long-term demands discussed in part i. above.

iii. **Operational Benefits -** The NPS 36 Panhandle Loop is a natural extension of the existing NPS 36 Panhandle Pipeline constructed as part of the 2017 Panhandle Reinforcement Project (EB-2016-0186). This continuity of pipeline diameter ensures that the Company can complete consistent in-line inspections throughout the length of the system using a single tool which reduces:
(i) high-risk gas handling activities associated with pipeline cleaning and integrity assessments;
(ii) the station facilities and footprint that would otherwise be required if the pipeline diameter was reduced to NPS 30; and
(iii) the cost of the integrity program itself.

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[2] Exhibit I.STAFF.7 Attachment 1
[3] Exhibit I.STAFF.7 Attachment 1

ENBRIDGE GAS INC.

Answer to Interrogatory from
Energy Probe ("EP")

INTERROGATORY

Reference:

Exhibit E, Tab 1, Schedule 1. Page 6, paragraph 9

Preamble:

This schedule indicates that the Project has a NPV of negative $95 million and a PI of 0.63.

Question:

Considering the large negative NPV and a low PI of the proposed project did Enbridge consider asking contract customers with increased demand to pay a contribution or a surcharge? Please discuss.

Response

The economic analysis of the Project was completed in accordance with E.B.O. 134 Report of the Board ("E.B.O. 134"), as the Project consists entirely of transmission pipeline infrastructure to which distribution customers do not directly connect. Asking customers to pay a contribution or a surcharge is not applicable to the Project. /U

Please see Exhibit A, Tab 4, Schedule 1, Paragraphs 21-23 regarding Enbridge Gas's outreach to customers who indicated their intention to submit an EOI bid regarding the requirement for CIAC.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, p. 2-3, 7, 11, 13 including Table 1 & Attachments 1 & 2

Preamble:

EGI evidence states: Natural gas is uniquely suited to the greenhouse sector. It is used to heat greenhouses and to supply the carbon dioxide requirements ("CO2") of the growing plants. A common practice within the greenhouse sector is to capture the CO2 that would normally be emitted into the atmosphere upon combustion of natural gas and use it within the greenhouse where it is consumed by the growing plants, resulting in faster growth and increased production.

Question:

For the schematic structure provided in Attachment 1, in tabular format, please provide the throughput and direction through:

a) Dover Transmission to the NPS 16 & separately to the NPS 20
b) Leamington North Gate (please add pressure also)
c) Grand Marais Station
d) Sandwich Station
e) Ojibway Measurement (table shows demand of 30TJ – seeking clarification)
f) Detroit River Crossing

Response

The Company is interpreting FRPO's reference to "Attachment 1" to be Exhibit B, Tab 2, Schedule 1, Attachment 1.

Please see Table 1 below for Winter 2024/2025 throughput and gas flow direction, without the proposed Project. In response to the clarification requested for item e), there are several distribution stations in the vicinity of Ojibway Measurement that were assigned to the Ojibway Measurement node within the schematics. Exhibit B, Tab 2, Schedule 1, Attachment 1, shows that on design day there is 29,193 GJ/d of demand being served to customers from that general location. Thus the 60,138 GJ/d of Ojibway supply coming into the Panhandle System at the River Crossing passes through the Ojibway Measurement Station, serves the demand associated with the distribution stations near to the Ojibway Measurement Station, and the remaining 30,945 GJ/d flows easterly into the NPS 16 Panhandle System to serve other customer demands.

Table 1: Throughput and Direction at Existing Facilities Without the Project

W24/25 Existing Facilities (without Proposed Project)	Throughput	Direction	Requested Pressure
Location	**GJ/d**	**Flow**	**kPag**
Dawn Supply	742,043	Westerly	
Dover Transmission Station to NPS 16	175,554	Westerly	
Dover Transmission Station to NPS 20	457,657	Westerly	
Leamington North Gate Station	14,260	South	1580
Grand Marais Station	25,819	Westerly	
Sandwich Station	145,562	Westerly	
Ojibway Measurement to Windsor	60,138	North/South	
Detroit River Crossing (Ojibway Supply)	60,138	Easterly	

ENBRIDGE GAS INC.

Answer to Interrogatory from
Federation of Rental-housing Providers of Ontario ("FRPO")

INTERROGATORY

Reference:

Exhibit B, Tab 2, Schedule 1, p. 3, 5, 6, 7 and
EB-2016-0186 including Exhibit K2.1 Union_Further Correspondence_20161122

Preamble:

EGI evidence states: Two NPS 12 pipelines ("Detroit River Crossing" or "the crossings") connect the NPS 16 Panhandle Line at Ojibway to the Panhandle Eastern Pipeline System ("Panhandle Eastern")2 at the International Border. This interconnection was established in 1947 and is commercially known as Ojibway. The Detroit River Crossing MOP is 2930 kPag.
[2] Panhandle Eastern Pipe Line Company, LP is owned by Energy Transfer Equity L.P.

We would like to understand more about EGI's review of the potential for increasing supply at Ojibway. During the last major Panhandle Reinforcement proceeding, EB-2016-0186, there was significant evidence regarding Energy Transfer's desire to increase deliveries to Dawn including the potential to obligate at Ojibway. We understand that EGI held discussions with Rover, of which Energy Transfer holds an ownership position, but we are interested in discussions with Energy Transfer who owns the Panhandle Eastern Pipeline.

Question:

Please provide the most recent determination of cost estimate for increasing capacity across the Detroit River.

Response

Enbridge Gas does not accept FRPO's interpretation of the Panhandle Reinforcement Project proceeding (EB-2016-0186) in the preamble, specifically the statement that "there was significant evidence regarding Energy Transfer Partners' desire to increase deliveries to Dawn including the potential to obligate at Ojibway". Energy Transfer did not express interest in increasing deliveries at Dawn as part of the Panhandle Reinforcement Project proceeding. Rather, Rover LLC executed contracts for Ojibway to Dawn C1 service that were presented in that same proceeding and has not requested incremental capacity since.

Please refer to Exhibit C, Tab 1, Schedule 1 for Enbridge Gas' assessment of incremental firm supply availability through the PEPL facilities at Ojibway.

Currently, the capacity of the Detroit River Crossings is 195 mmscfd (~217 TJ/d) based on the Presidential Permit. However, Enbridge Gas's ability to import this volume is limited by the Windsor Market and facilities available to transport the imported gas from Ojibway to Dawn throughout all months of the year. In the summer, additional facilities are required at the west end of the Panhandle system to transport gas incremental to the available market to Dawn. In the winter, facilities are still required from Dawn to meet peak day demands that cannot be entirely served from Ojibway. Also, the ability to import supply at Ojibway is limited by the Panhandle Eastern Pipeline's ("PEPL") ability to deliver gas to the Detroit River Crossing.[1]

Enbridge Gas is currently unable to import the 217 TJ/d, as the existing system is limited by the current Windsor Market and the current Sandwich Compressor (please see the response to Exhibit I.FRPO.10).

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[1] In the previous Panhandle Reinforcement project (EB-2016-0186) Enbridge Gas evaluated increased capacity across the Detroit River which included additional Enbridge Gas facilities, PEPL facilities in Michigan, and the cost for incremental firm Ojibway deliveries. As noted in EB-2016-0186, Exhibit B.IGUA.9 d), Enbridge Gas (formerly Union Gas) stated: "Union did contemplate increased capacity by replacing the existing NPS 12 Detroit River Crossing pipelines with a single NPS 20 pipeline. This alternative is complex requiring significant new facilities on the PEPL system upstream of the Detroit River Crossing to provide a minimum of 3,450 kPag (500 Psig) at Ojibway and new facilities on Union's Panhandle System between Ojibway and consuming markets. Without new upstream facilities, a new river crossing would still only be able to deliver 2,930 kPag (425 Psig), the MOP of the upstream PEPL pipeline facilities. Union explored this alternative with PEPL however the large amount of facilities required made this alternative cost prohibitive. PEPL would also require significant compressor and pipeline investment to increase the delivery pressure to Union. Even if the capital costs were reasonable for such an alternative, Union would be required to contract for long term upstream transportation (at least 10 years) from Panhandle Field Zone to Ojibway to support the additional facilities required on the PEPL system."

To be able to import the 217 TJ/d, additional facilities are required within the Panhandle System including: replacement of the Detroit River Crossings at a 3450 kPa MOP, an NPS 20 pipeline looping the current NPS 16 from the Detroit River Crossing to Sandwich Compressor Station, and two compressor units at Sandwich Compressor Station (one for incremental volumes, and a “loss of critical unit” compressor).

Table 1 below summarizes the cost of these facilities, but does not include the cost of any incremental firm Ojibway deliveries, or costs associated to PEPL facilities.[1]

With this additional infrastructure and incremental supply, 7.8 km of NPS 36 pipeline would still be required (in addition to Dawn Yard facilities) to provide the equivalent 168 TJ/d of system capacity provided by the proposed Project, which is also shown in Table 1. Therefore, the facility costs alone to increase the supply of gas from Ojibway is not a cost-effective alternative to the proposed Project.

Table 1

Cost Summary ***Facility Requirements Only***	**Estimated Cost ($ millions)**
Replace Detroit River Crossing (NPS 20)[1] and increase MOP[2]	$30
17 km NPS 20 pipeline from Detroit River Crossing to Sandwich Compressor Station, and two compressor units at Sandwich Compressor	$237
7.8 km of NPS 36 Panhandle looping pipeline, station facilities and Dawn Facilities	$220
In-direct Overheads	$135
Total Facility Cost including in-direct overheads (Excluding Non-facility Supply costs)	$668

NOTES:
1 - Assumes 60% of total River Crossing Costs, based on current Enbridge Gas ownership.
2 - Assuming PEPL has upgraded facilities to provide up to 3,450 kPag (500 Psig)

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Reference:

"Growth is forecast to occur across the entire Panhandle System with concentration in the Leamington-Kingsville and Windsor areas.

Question:

Please provide a copy of all documents and specific information sources outlining the growth assumptions that would affect the Panhandle system as noted above.

Response

The growth forecast is provided in Exhibit B, Tab 1, Schedule 1. The growth forecast is /U
informed by the EOI bids, in which customers provided their volume, location and approximate timing of demand. Please see the response at Exhibit I.STAFF.4

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Reference:

"The Project as proposed is designed to reliably serve increased demands for firm service in the Panhandle Market, including, in particular, incremental demands from the greenhouse, automotive, and power generation sectors." [A/2/1 Page 2]

Question:

a) What is the current peak demand (GJ) for the Panhandle system and what will be the peak demand capacity if the project is approved and completed.
b) Please provide a copy of all firm contracts and firm commitments from greenhouse, automotive, and power generation sectors customers that drive the incremental peak demand identified.
c) Please provide a table showing each customer incremental natural gas peak demand that would be supplied by the proposed pipeline and include columns indicating the start and end date for each firm contractual commitment related to those peak demand commitments.
d) Please identify any additional peak demand capacity that the proposed project would provide in excess of the contracted demand identified.
e) Please confirm that the Panhandle system has the capacity to provide for ex-franchise delivery (e.g. export) and what the capacity is available for ex-franchise deliver.

Response

a) The current (W22/23) Panhandle System peak day demand is 698,025 GJ/d and the system capacity is 736,512 GJ/day. The system capacity will be 904,196 GJ/day once the Project is placed into service. Please see Exhibit I.STAFF.6, Table 1. /U

b) Please see the contract and commitment templates set out in Attachment 1 of this response, which are representative of all executed commitments from customers. Please see the response to part c) below for customer-specific bid details.

c) – d)
Please see Exhibit I.STAFF.24, part a). /U

e) Confirmed.

Enbridge Gas's Panhandle System connects with the Panhandle Eastern Pipeline Company ("PEPL") system at Ojibway. The capacity for ex-franchise delivery is limited by the ability for PEPL system capacity to accept gas, which isn't known by Enbridge Gas at this time. There are currently no customers of Enbridge Gas with C1 service from Dawn to Ojibway and no requests have been received for this service by Enbridge Gas.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Reference:

"203 TJ/d resulting from the Project will support the continued reliable and secure delivery of natural gas to the growing residential, commercial, and industrial customer segments within the Panhandle Market" [A/3/1 pg.3]

"Contract rate customer demand makes up approximately 98% of the capacity of the proposed Project." [B/1/1 Pg.7]

Question:

a) Please explain how 98% of the project capacity is allocated to contract rate demand, and there can still be 203 TJ/d of additional unallocated future capacity left from the proposed project.
b) Please explain how the 203 TJ/d of additional unallocated future capacity will be used until it is needed in the future to serve in-franchise customers. Also, if it is idle capacity not planned to be used, please indicate.

Response

a) and b)
For clarity, Enbridge Gas is forecasting that all 168 TJ/day of the additional capacity resulting from the Project will be needed to meet customer demand through Winter 2028/2029. Enbridge Gas is forecasting that contract rate customer demand will make up approximately 94% of the additional 168 TJ/day capacity created. /U

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Question:

a) Please list all municipal/community energy plans (or equivalent such as energy & emission plans, etc.) were considered when planning for this project.
b) Please provide a copy of all DSM related options and analysis conducted to serve current and incremental customers served by the Panhandle system.

Response

a) Please see the response to Exhibit I.EP.2.

b) The Company's assessment of Enhanced Targeted Energy Efficiency ("ETEE") IRP alternatives can be found at Exhibit C, Tab 1, Schedule 1, Pages 20 to 21. /U

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Reference:

"Enbridge Gas has completed an alternatives assessment to determine the optimal solution to meet the identified system need" [C/1/1 Pg. 3]

Question:

Please provide a copy of all materials (e.g. reports, presentations, correspondence, etc. related to the alternatives assessment.

Response

The following represent the entirety of materials related to the Alternative Assessment:

- On September 16, 2021, Enbridge Gas completed a Request for Proposal ("RFP") for a Firm Exchange Service. The RFP package is included at Exhibit C, Tab 1, Schedule 1. Attachment 1.
- On September 19, 2021, Enbridge Gas held a virtual meeting with members of Energy Transfer Partners to determine whether they were interested in participating in the Firm Exchange Service RFP. The meeting invitation and minutes are included in the response at Exhibit I.FRPO.7, Attachment 1.
- On October 7, 2021 Enbridge Gas received a non-binding bid for a Firm Exchange Service which is included at Attachment 1 to this response.
- As part of the alternatives assessment for non-facility alternatives Enbridge Gas engaged Posterity. Communications between Posterity are set out in the response at Exhibit I.ED.7, Attachment 6, and the Posterity IRP Analysis can be found at Exhibit C, Tab 1, Schedule 1, Attachment 2.
- On March 10, 2022, Enbridge Gas summarized Project alternatives to support a presentation made to the Company's Capital Allocation Committee on April 4, 2022. The summary of Project alternatives can be found at Attachment 2 to this response, and the presentation made to the Capital Allocation Committee can be found at Attachment 3 to this response.

- Prior to the development of the current Leave to Construct application, Enbridge Gas refreshed the summary of Project alternatives to support decision making. That summary is set out at Attachment 4 to this response.
- The proposed Project received Enbridge Board of Director Approval in May 2022, based on the presentation materials set out at Attachment 5 to this response.
- On January 11, 2023, Enbridge Gas presented the incremental capital breakdown to the Capital Allocation Committee. The presentation can be found at Attachment 6 to this response.
- On April 12, 2023, Enbridge Gas presented the Projects updated scope and incremental capital request to the Investment Review Committee. The presentation can be found at Attachment 7 to this response.
- The proposed Project received Enbridge Board of Director Approval for incremental capital in April 2023, based on the presentation materials set out at Attachment 8 to this response.
- In June 2023, Enbridge Gas refreshed the summary of Project alternatives to support decision making. That summary is set out at Attachment 9 to this response.

Panhandle Regional Expansion Project Incremental Capital Seeking Stage 3

Capital Allocation Committee

January 11, 2023

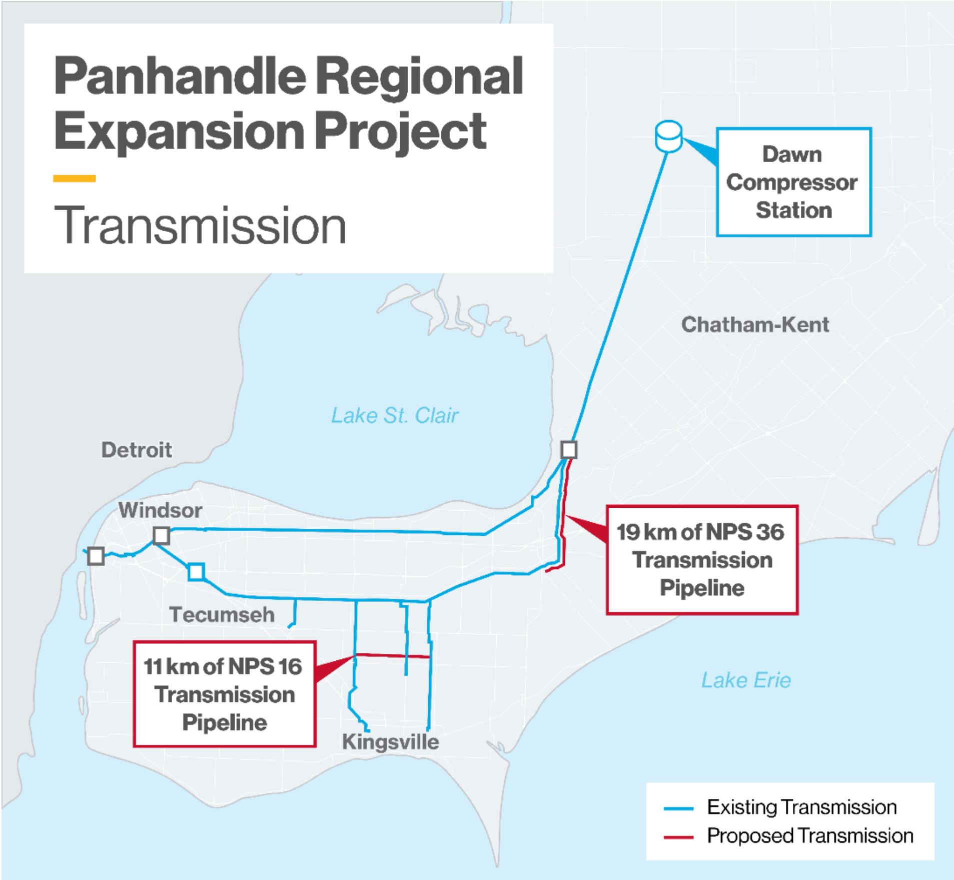
Purpose: Requesting Capital Allocation Committee for approval to proceed to the IRC (Stage 3)

ENBRIDGE

Background

- Seeking C$113 MM of incremental capital for the Panhandle Regional Expansion Project (PREP) that supplies natural gas from the Dawn Hub to customers west of Dawn. The Project consists of constructing two transmission pipelines and measurement facilities at Dawn Compressor Station
- The project received full funding approval on May 4, 2022 by EI Board of Directors for C$314 MM including C$54 MM of in-direct overheads at a Class 3 cost estimate with a DCFROE of 8.8%
- The project has since experienced increased costs of C$113 MM ($90 MM direct capital including IDC plus $23 MM in-direct overheads) driven by prime contractor RFP estimates and internal labour/outside services increases
- The project is currently in a Leave to Construct (LTC) proceeding with the OEB and was placed into abeyance December 5, 2022 in order to update the evidentiary record of a material change of increased project cost
- The project is expected to receive a cost-of-service regulated return with an updated DCFROE of 8.1%
  - Incremental costs of C$113 MM assumed to be included at next rebasing term starting in 2029

Project Map



Regulated project that supports significant EGI customer growth

Project Description with Incremental Capital

ENBRIDGE

Scope	• 36-inch pipeline ~19 km from Dover Station towards Comber Station • 16-inch pipeline ~11 km between Kingsville East Line and Leamington North Lines • Measurement facilities at Dawn Compressor Station
Approved Capex	• C$314 MM ($260 MM direct capital including IDC plus $54 MM in-direct overheads) (Class 3)
Incremental Capex	• C$113 MM ($90 MM direct capital including IDC plus $23 MM in-direct overheads)
Key Dates	• Investment Review Committee – Jan 2023 • ENB Board Request for Incremental CAPEX approval – Feb 2023 • Ontario Energy Board Approval Target – June 2023 • In-Service Date – Nov 2023 (36-Inch Pipeline & Measurement Facilities)[1] • In-Service Date – Nov 2024 (16-Inch Pipeline)[1]
Capacity	203 TJ/d of Panhandle Transmission System Capacity
Customers	• In-franchise contract customers (Greenhouse & Power Generation markets) and residential demand growth • Customer commitment to the project is currently 80% of the total proposed project capacity

Project Scorecard

Low	Medium	High

Key Attribute	Rank	Considerations
Strategic	High (green)	• Core business growth project • Most rapidly expanding transmission system
Commercial	High (green)	• Regulated cost of service project • LTC application in abeyance • Seeking cost recovery for incremental CAPEX at earliest opportunity
Financial	High (green)	• Base case DCFROE 8.1%
Ability to Execute	High (green)	• No expropriation included in schedule • Low complexity; rural terrain • Full mainline can be completed with a June 2023 start date; ~5km NPS 36 required to meet winter 2023/2024 firm demand (year 1 growth forecast)
ESG	Medium (orange)	• While the project will result in an emissions increase of ~5000 tCO2e annually (<0.7%), it does not have a material impact on the total GDS emissions intensity

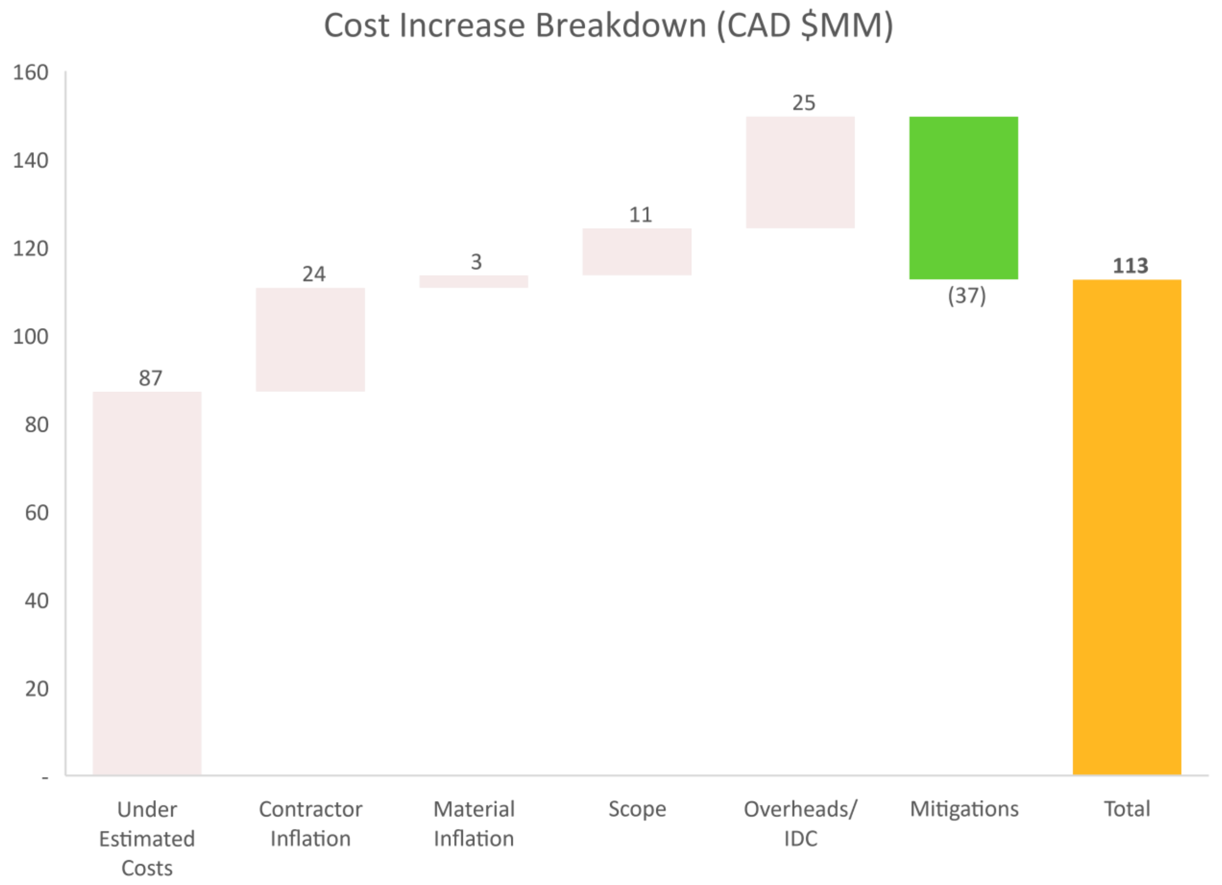
[1] No changes to ISD vs Original BOD memo

Incremental Capital Breakdown

- **Underestimated Costs (+C$87 MM)**
  - RFP estimates higher than Request for Information (RFI) responses
    - RFI estimate accuracy +/- 30%
    - RFI bids excluded Dawn NPS 42 header
  - Stations engineering consultant underestimated construction duration and labour hours
    - Estimated 78,000 labour-hours vs. current estimate of 306,000
- **Unforeseen Inflation (+C$27 MM)**
  - Contractor pricing anticipates increases to rental equipment rates, fuel prices, and contract labour rates
  - Increased inspection hours and rates based on more detailed scope definition
- **Scope Clarification (+C$11 MM)**
  - Scope additions added during detailed design
    - Increases in quantities of diameter-inch welding, cut & fill, large bore valves, actuators, and cabling
  - More trenchless crossings and added depth to open cuts
- **Overheads / IDC (+C$25 MM)**
- **Mitigations (-C$37 MM)**
  - Negotiate prime contractor terms of contract ($19 MM)
  - Scope refinement for station design ($18 MM)

Summary of Incremental Capital Approvals (C$ MM)

Original Board Approval – May 2022 (Class 3)	314
Incremental Capital Appropriation Request	**113**
Revised Total Capital	427



Management has high confidence in achieving the mitigating savings and working to identify other potential costs reductions

Regulatory Impacts

ENBRIDGE

Low | Medium | High

Key Considerations	Assessment	Commentary
OEB LTC Approval: Timeline	Green	• EGI placed project in abeyance with OEB on Dec 5, 2022 due to discovery of a material change in project cost • ENB will file a comprehensive updated cost and evidence package at earliest opportunity • Seek streamlined continuation of the LTC proceeding and install facilities to meet 2023/2024 customer demand at a minimum • OEB approval timeline delayed up to 3 months (March to June) if full funding approval received in Feb 2023
OEB LTC Approval: Project Need	Green	• Project continues to be economic and in the public interest serving incremental demand for EGI's most rapidly expanding greenhouse sector, Ontario power generation customer & Stellantis (NextStar) • Continuing to increase customer commitments for the project; significant support from municipal CAO's, regional Chambers of Commerce, Ministry of Economic Development
Project Cost Recovery	Medium	• Project has committed costs of: – C$57 MM as of Dec 1, 2022 – Total of C$74 MM by ENB BoD meeting in Feb, 2023 – Total of C$130 MM by OEB LTC Approval in June 2023 • Customer costs will be recovered through rates from commercial agreements with contract customers • Remaining revenue requirement will be recovered from ratepayers – Original BOD approved amount (C$314 MM) to be included in 2024 Rebasing – Incremental Capex (C$113 MM) to be included in 2029 Rebasing • Project originally assumed seeking OEB approval using Incremental Capital Module (ICM) mechanism – ICM threshold not met based on OEB approved 2023 proceeding[1]

The project continues to demonstrate a strong project need to serve customer growth and is still the most optimal solution

[1] Impact shown on the financial evaluation slide

Financial Evaluation

ENBRIDGE

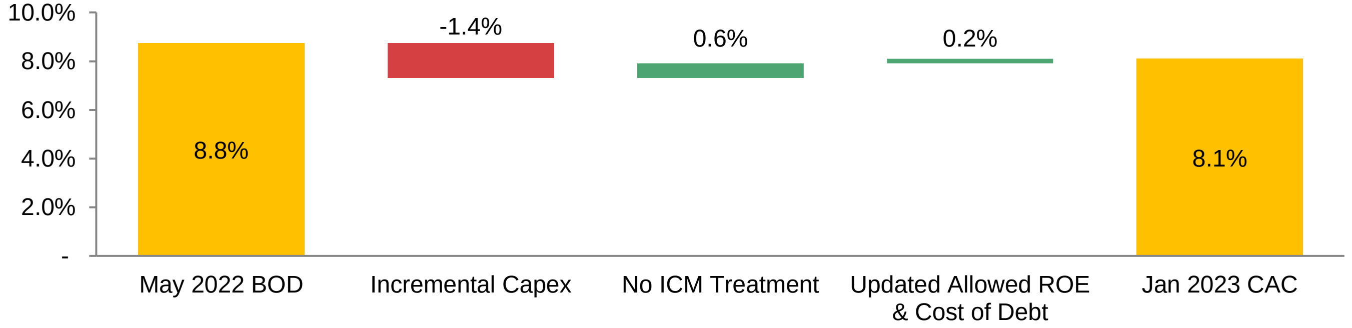
Project Description

- **Incremental Capex:** To be included in Rate base starting in 2029
  - Losing the recovery on return on capital and return of capital for the 2024-2028 period
- **No ICM Treatment:** ENB to keep some CCA tax benefits[1]
  - ICM treatment was assumed in the original base case in 2022
- **Updated Allowed ROE & Cost of Debt:** The revenue requirement for the total project is assumed as annual cost of service, with an allowed ROE of 8.9% in 2023, 9.2% for 2024-2028 and 9.1% for each subsequent period[2]
- Evaluation parameters include:
  - C$427 MM CAPEX (including IDC and overheads)
  - 40-year evaluation horizon
  - 64:36 debt to equity ratio, 4.7% cost of debt
  - 26.5% Tax Rate

Financial Outlook

in $MM	2022-23	2024	2025	2026	2027	2028	2029
Equity Cash Flow	(104.4)	(25.2)	8.5	10.4	10.0	9.7	15.6
EBITDA	(11.2)	13.4	23.3	24.4	24.8	25.1	33.9
Earnings	11.4	7.7	7.6	7.1	6.7	6.4	12.3
DCF	12.0	14.7	16.7	16.3	16.0	15.6	21.6
D/EBITDA		19.7x	11.3x	10.5x	10.1x	9.8x	7.1x
Annual ROE		5.8%	5.1%	4.9%	4.7%	4.6%	9.0%

DCFROE	**8.1%**
EV/ 2025 EBITDA	18.3x
EV/ 2029 EBITDA	12.6x



Investment realizes a strong return from low-risk cost of service investment

[1] ENB to keep CCA tax benefits related to capital subject to the half year rule, incremental CCA tax benefits related to the Accelerated Investment Incentive are not included

[2] Assumption reflects the latest forecast of allowed ROE for EGI

Risk Matrix Signoffs

ENBRIDGE

Team/Area	Responsibilities	Signoff
Project Execution	Heidi Bredenholler-Prasad	✓
Integrity	Jim Sanders	✓
Asset Utilization	Tanya Mushynski & Jim Redford	✓
Operations	Jim Sanders	✓
Insurance	Cathy Ward	✓
Tax	Leslie O'Leary	✓
Land	Vik Kohli	✓
Environmental	Vik Kohli	✓

Team/Area	Responsibilities	Signoff
Stakeholder	Keith Boulton & Mike Fernandez	✓
Regulatory	Malini Giridhar	✓
Credit	Jonathan Gould	✓
Accounting	Chris Johnston	✓
Treasury	Jonathan Gould	✓
Investment Review	Falyne Chave	✓
GHG	Malini Giridhar	✓
Market Price Risk	Jonathan Gould	✓

Panhandle Regional Expansion Project Revised Scope

Investment Review Committee
April 12, 2023

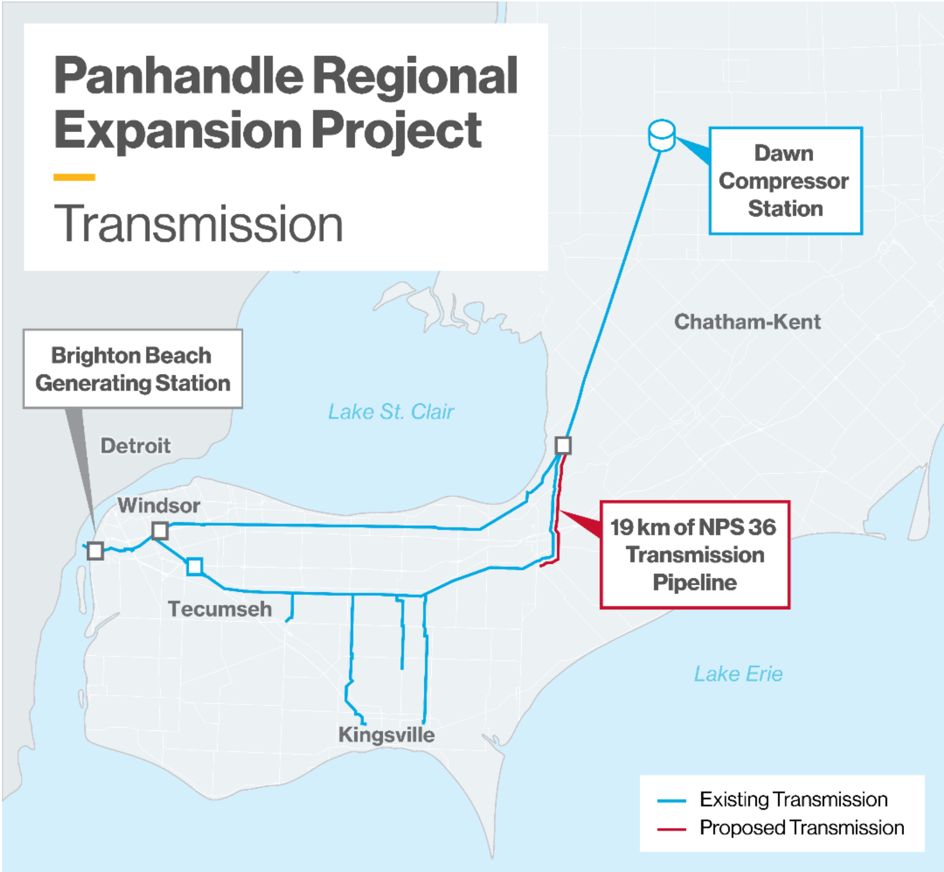
ENBRIDGE®

Background

ENBRIDGE

- The Panhandle Regional Expansion Project (PREP) supplies natural gas from the Dawn Hub to a growing customer base west of Dawn
- The original project scope included 19 km of NPS 36 pipe, measurement facilities at Dawn Compressor Station and 11 km of NPS 16 pipe. PREP received full funding approval in 2022 by EI Board of Directors for C$314 MM with a DCFROE of 8.8%
- The project will require an incremental C$45 MM due to:
  - Project cost increase of +C$114 MM driven by inflationary pressures and identified gaps in the original cost basis
  - Offset by the scope removal of the NPS 16 pipeline of -C$69 MM
- Updating the EGI Rebasing Application with a levelized cost recovery[1] mechanism for the 2024 project costs of C$253 MM. The 2025 project costs of C$106 MM will be recovered under the base capital included in EGI 2025 rates
  - EGI portfolio view DCFROE of 9.2%
  - Most likely scenario for PREP 2024 capital is to receive levelized cost recovery[1] treatment in 2024 due to it being a rebasing year and 2025 capital is accommodated in current capital plan. This will ensure a DCFROE at approved ROE of 9.2%. Should it not receive such treatment, worst case scenario is 2025 capital will be recovered in 2029 at next rebasing which leads to a DCFROE of 8.7%

Project Map



Regulated project that supports significant EGI customer growth

[1] See Financial Evaluation slide for more details

Project Description with Revised Scope

ENBRIDGE

Revised Scope	• 36-inch pipeline ~19 km from Dover Station towards Comber Station • Measurement facilities at Dawn Compressor Station
Original Capex	• C$314 MM ($260 MM direct capital including IDC plus $54 MM in-direct overheads)

Revised Scope Capex	• C$359 MM ($289 MM direct capital including IDC plus $70 MM in-direct overheads)
	  • 2024 ISD: $253 MM
	  • 2025 ISD: $106 MM

Key Dates	• [ENB Board Request for Incremental CAPEX approval – May 2023] • Ontario Energy Board (OEB) LTC Application – June 2023 • OEB Approval Target – Jan 2024 • In-Service Date – Nov 2024 & Nov 2025
Capacity	• 167 TJ/d of Panhandle Transmission System Capacity
Customers	• In-franchise contract customers (Power Generation, Greenhouse and other Industrial markets) and residential growth

Original vs Revised Scope

	Capex $ MM	Base System Capacity (TJ/d)	Incremental Project Capacity (TJ/d)	Total Market (TJ/d)	ISD
Original	314	713	203	916	2023 & 2024
Revised	359	737	167	904	2024 & 2025

Project Scorecard

Low | Medium | High

Key Attribute	Rank	Considerations
Strategic	High	• Core business growth project • Most rapidly expanding transmission system
Commercial	High	• Regulated cost of service project • 2025 project costs recovered in 2025 within existing base capital
Financial	High	• EGI portfolio view DCFROE 9.2%
Ability to Execute	High	• Delayed land acquisition for the NPS 36 pipeline ROW due to a single landowner (last 700m) may require shortened loop or land expropriation
ESG	Medium	• While the project will result in an emissions increase of ~4100 tCO2e annually, it does not have a material impact on the total GDS emissions intensity (<0.5%)

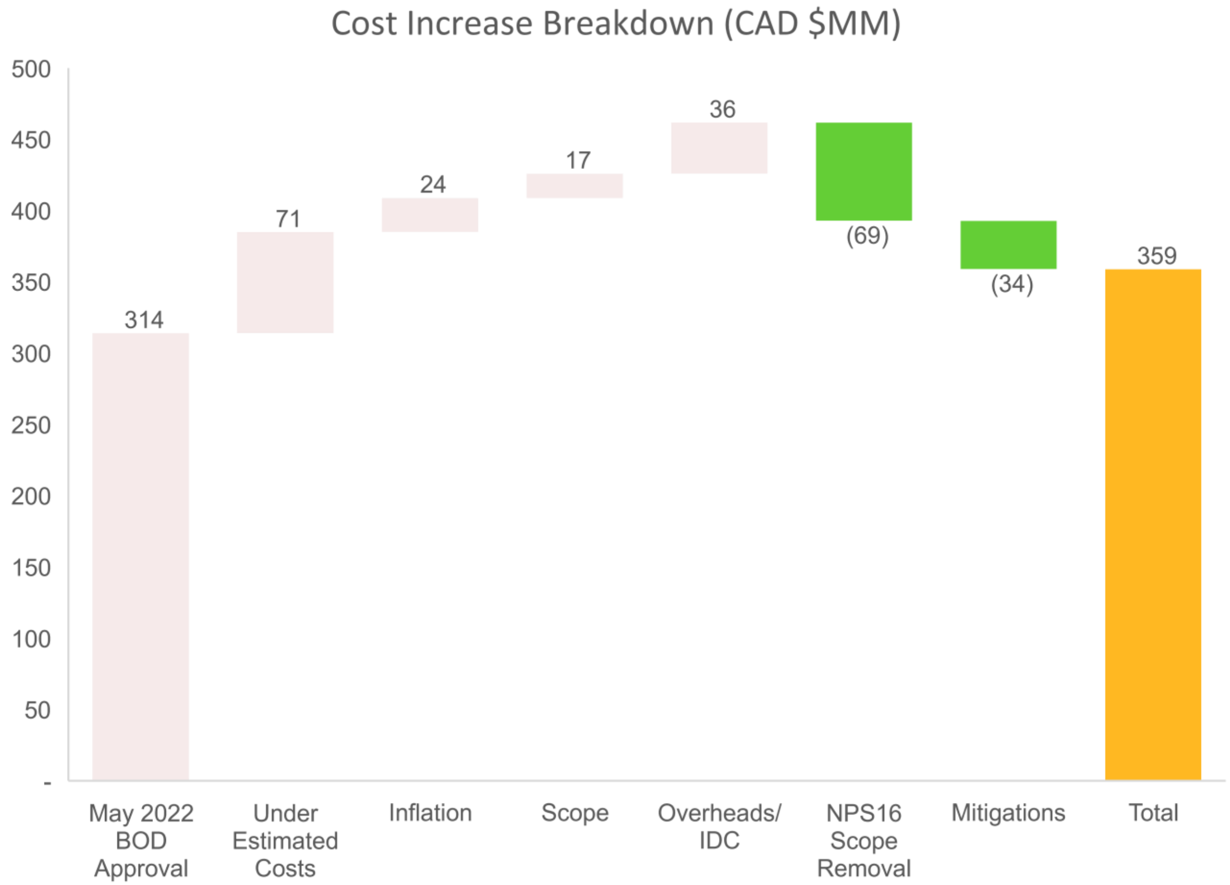
Incremental Capital Breakdown

- **Underestimated Costs [Volume of Work] (+C$71 MM)**
  - Contractor RFP estimates higher than Request for Information (RFI) responses ($54 MM)
  - Engineering consultant & RFI Input underestimated station construction duration and labour hours ($17 MM)
- **Incremental Cost Inflation (+C$24 MM)**
  - Material cost increases ($2 MM)
  - Contractor pricing anticipates increases to rental equipment rates, fuel prices, and contract labour rates ($22 MM)
- **Scope Clarification [IFR30 to IFB*] (+C$17 MM)**
  - Scope clarifications added during detailed design ($9 MM)
  - More trenchless crossings and added depth to open cuts ($5 MM)
  - Increased inspection hours and rates based on more detailed scope definition ($3 MM)
- **Overheads / IDC (+C$36 MM) [OEB % of spend formula]**
- **NPS16 Lateral Scope Removed (-C$69 MM)**
  - Scope deferred due to changing customer demand profile
- **Mitigations – current view (-C$34 MM)**
  - Negotiate prime contractor terms and conditions ($19 MM)
  - Streamlined design for station scope ($15 MM)

*IFR30 – Issued for Review at 30% Engineering; IFB – Issued for Bid (RFP)

Summary of Incremental Capital Approvals (C$ MM)

Original Board Approval – May 2022 (Class 3)	314
Incremental Capital Appropriation Request	**45**
Revised Total Capital	359



Work continuing with vendors in expectation of Q2 2024 Construction Start

Regulatory Impacts

ENBRIDGE

Low	Medium	High

Key Considerations	Assessment	Commentary
OEB LTC Approval: Timeline	High (green)	• EGI placed project in abeyance with OEB on Dec 14, 2022 due to discovery of a material change in project cost • EGI will file a comprehensive update to evidence in June 2023 (including adjusted facility scope and costs) and will seek streamlined continuation of the LTC proceeding
OEB LTC Approval: Project Need	High (green)	• EGI completed an Expression of Interest in February – April of 2023 to confirm the demand forecast • Project continues to be economic and in the public interest serving incremental demand for EGI's rapidly expanding greenhouse sector, power generation & other industrial and residential growth • Continuing to increase customer commitments for the project; significant support from municipal CAO's, regional Chambers of Commerce, Ministry of Economic Development
Project Cost Recovery	Medium (yellow)	• Project has committed costs of: – Total of C$72 MM by ENB BoD meeting in May 2023 – Total of C$77 MM by EGI Rebasing Application Approval in Q4-2023 – Total of C$193 MM by OEB LTC Approval in Jan 2024 • Costs will be recovered through rates from commercial agreements with contract customers • Remaining revenue requirement will be recovered from ratepayers – Updating the EGI rebasing application with a levelized cost recovery mechanism proposal for the 2024 project costs with decision expected by Q4-2023 – The 2025 project costs will be recovered under the base capital included in EGI 2025 rates

The project continues to demonstrate a strong project need to serve customer growth and is still the most optimal solution

Financial Evaluation

ENBRIDGE

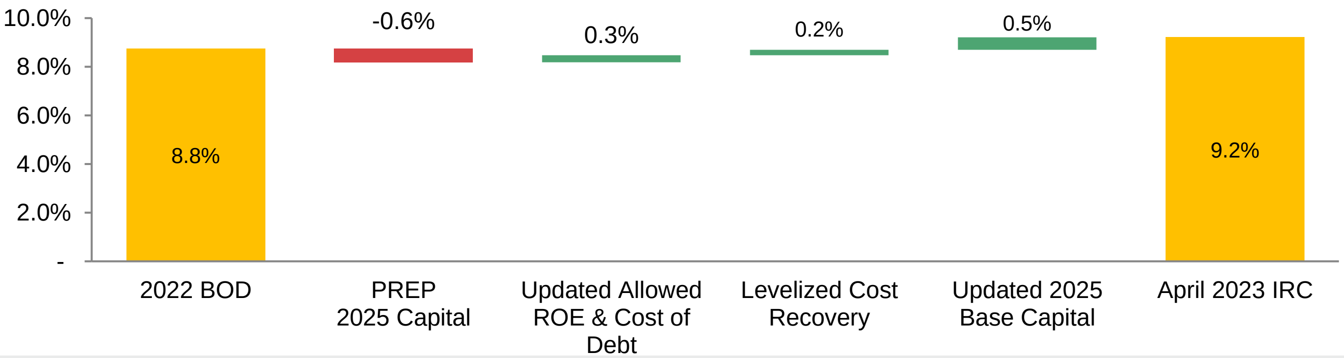
Project Description

- **PREP 2025 Capital:** 2025 in-service capital was not included in 2024 EGI Rebasing Application
- **Updated Allowed ROE & Cost of Debt:** The revenue requirement for the total project is assumed as annual cost of service, with an allowed ROE of 8.9% in 2023, 9.2% for 2024-2028 and 9.1% for each subsequent period[1]
- **Levelized Cost Recovery:** The annual recovery of the 2024 ISD Revenue Requirement reflects the 5-year average of 2024-2028, recovering the same amount each year
- **Updated 2025 Base Capital:** Reflects the recovery of 2025 in-service capital of C$106 MM under the base capital included in EGI 2025 rates
- Evaluation parameters include:
  - C$359 MM CAPEX (including IDC and overheads)
  - 40-year evaluation horizon
  - Debt to equity ratio consistent with 2024 Cost of Service filing – ramps up to 58:42 in 2028, 4.65% cost of debt
  - 26.5% Tax Rate

Financial Outlook

in $MM	2022-23	2024	2025	2026	2027	2028	2029
Equity Cash Flow	2.8	(99.2)	(19.3)	7.9	8.8	9.4	15.7
EBITDA	-	7.2	4.8	21.4	23.1	24.5	29.3
Earnings	2.8	15.4	3.7	8.7	9.1	9.5	12.4
DCF	2.8	15.8	9.1	16.5	16.9	17.3	20.2
D/EBITDA		25.9x[2]	45.2x[2]	9.7x	8.6x	7.8x	6.4x
Annual ROE		130.5%[3]	3.6%[3]	6.2%[3]	6.5%[3]	6.8%[3]	9.1%

DCFROE	**9.2%**
EV/ 2026 EBITDA	16.8x
EV/ 2029 EBITDA	12.3x



Investment realizes a strong return from low-risk cost of service investment

[1] Assumption reflects the latest forecast of allowed ROE for EGI

[2] High D/EBITDA multiples in 2024 & 2025 due to the utilization of a full year's worth of tax depreciation, while generating 2 months worth of revenue from the 2024 and 2025 in-service capital

[3] Annual ROE is lower than the allowed ROE of 9.2% in years 2025-2028 due to the effects of levelized cost recovery. 2024 will be earning above the allowed ROE

Risk Matrix Signoffs

Team/Area	Responsibilities	Signoff
Project Execution	Rob Watson	✓
Integrity	Jim Sanders	✓
Asset Utilization	Philippe Teijeira & Jim Redford	✓
Operations	Jim Sanders	✓
Insurance	Cathy Ward	✓
Tax	Leslie O’Leary	✓
Land	Vik Kohli	✓
Environmental	Vik Kohli	✓

Team/Area	Responsibilities	Signoff
Stakeholder	Keith Boulton & Mike Fernandez	✓
Regulatory	Malini Giridhar	✓
Credit	Jonathan Gould	✓
Accounting	Chris Johnston	✓
Treasury	Jonathan Gould	✓
Investment Review	Falyne Chave	✓
GHG	Malini Giridhar	✓
Market Price Risk	Jonathan Gould	✓

Panhandle Regional Expansion Project Revised Scope

Board of Directors
April 25, 2023

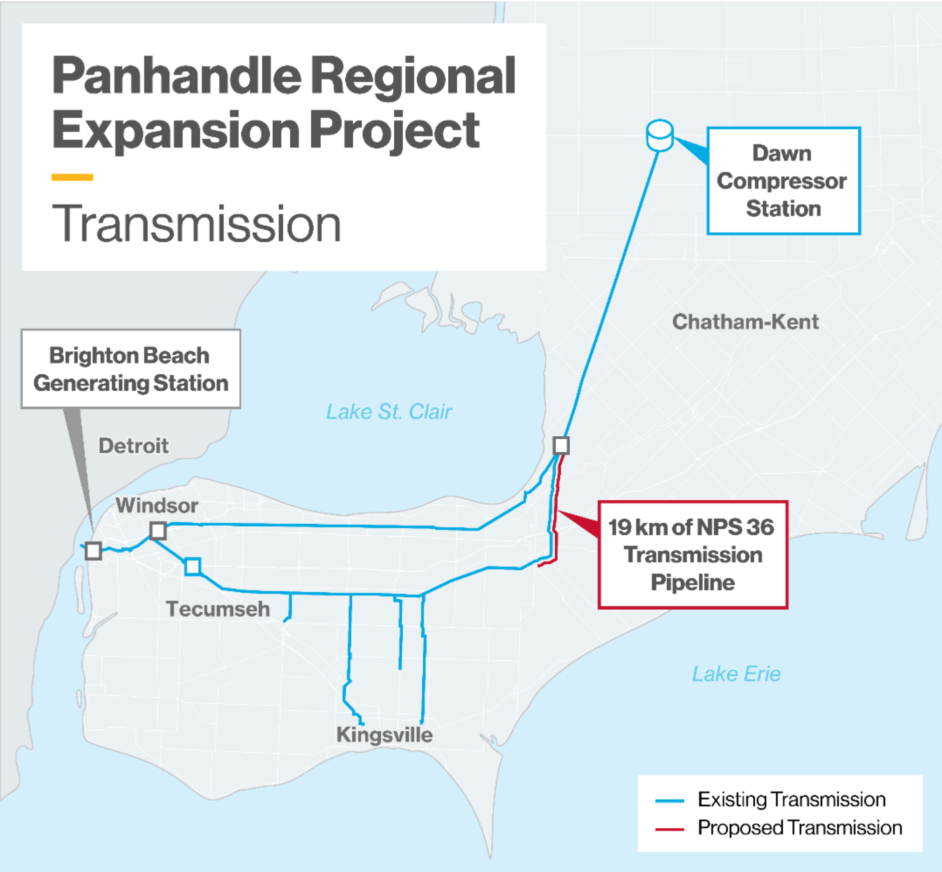
ENBRIDGE®

Background

ENBRIDGE

- The Panhandle Regional Expansion Project (PREP) supplies natural gas from the Dawn Hub to a growing customer base west of Dawn
- The original project scope included 19 km of NPS 36 pipe, measurement facilities at Dawn Compressor Station and 11 km of NPS 16 pipe. PREP received full funding approval in 2022 by EI Board of Directors for C$314 MM with a DCFROE of 8.8%
- The project will require an incremental C$45 MM due to:
  - Project cost increase of +C$114 MM driven by inflationary pressures and identified gaps in the original cost estimate
  - Offset by the scope removal of the NPS 16 pipeline of -C$69 MM
  - Project will be phased into service with the NPS 36 pipe in 2024 and the Dawn Facilities in 2025 based on demand forecast
- Updating the EGI Rebasing Application with a levelized cost recovery[1] mechanism for the 2024 project costs of C$253 MM. The 2025 project costs of C$106 MM will be recovered under the base capital included in EGI 2025 rates
  - EGI portfolio view DCFROE of 9.2%
  - Most likely regulatory scenario for PREP 2024 capital is to receive levelized cost recovery[1] treatment in 2024 due to it being a rebasing year. 2025 capital is accommodated in current capital plan
  - Worst case regulatory scenario is 2025 capital will be recovered in 2029 at next rebasing which leads to a revised project DCFROE of 8.7%

Project Map



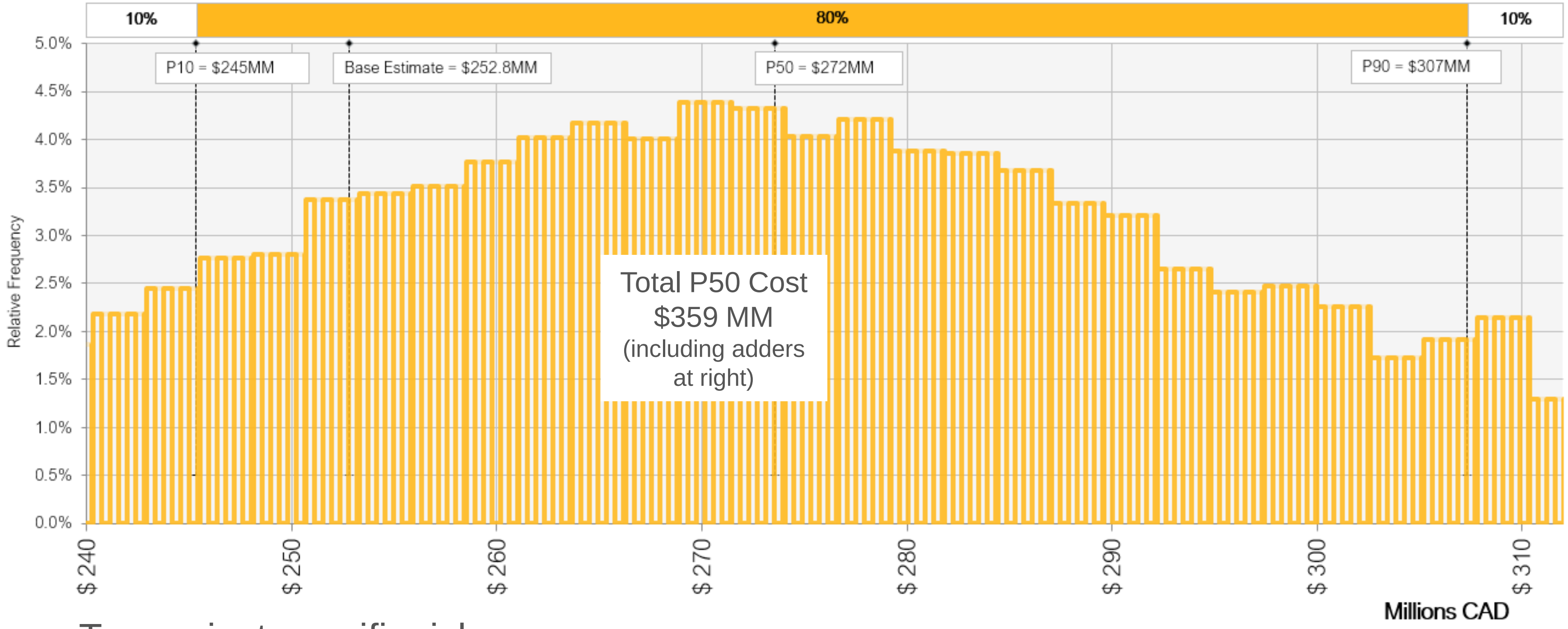
Regulated project that supports significant EGI customer growth

[1] See Financial Evaluation slide for more details

GDS: Panhandle Regional Expansion Project

ENBRIDGE

CAPEX Monte Carlo – Range of Cost Outcomes



	Estimate ($MM)
Total Project Estimate	**$359**
P50 Estimate (with contingency)	$272
Adders (scale with P50 estimate)	
Escalation, Interest During Construction (IDC), GDS Overheads	$87

Calculated Accuracy Range (P90 / P10 – In Relation to P50 value)
+12% / -10%

Top project specific risks:

- Delayed land acquisition for the NPS 36 pipeline ROW
- OEB Leave to Construct approval is delayed beyond January 2024

High level of certainty (tight accuracy band) driven by advanced project definition

Financial Evaluation

ENBRIDGE

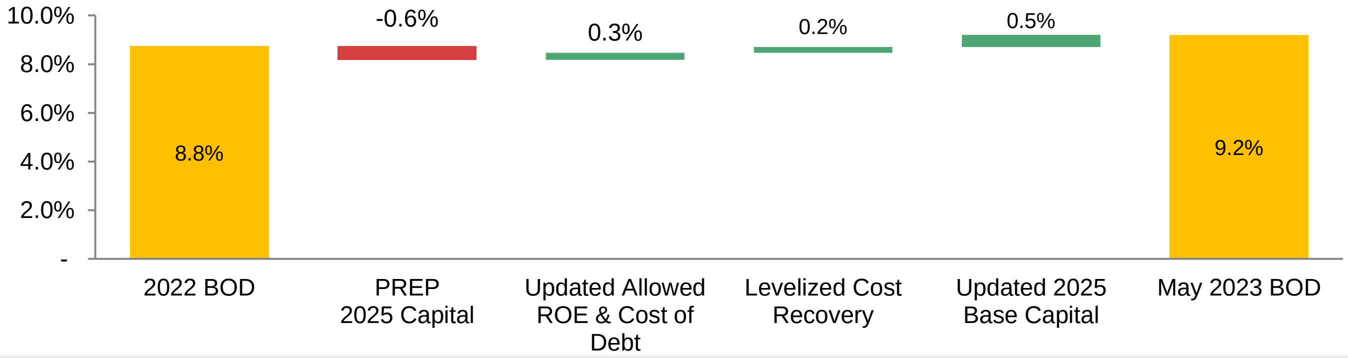
Project Description and Changes

- **PREP 2025 Capital:** 2025 in-service capital was not included in 2024 EGI Rebasing Application
- **Updated Allowed ROE and Cost of Debt:** The revenue requirement for the total project is assumed as annual cost of service, with an allowed ROE of 8.9% in 2023, 9.2% for 2024 – 2028 and 9.1% for each subsequent period[1]
- **Levelized Cost Recovery:** Recovery of the 2024 in-service capital is levelized across 2024 – 2028, earning the same revenue requirement each year
- **Updated 2025 Base Capital:** Reflects the recovery of 2025 in-service capital of C$106 MM with identified offsets in EGI's 2025 planned capital spend
- Evaluation parameters include:
  - C$359 MM CAPEX (including IDC, overheads, and C$21 MM contingency), Class 3
  - 40-year evaluation horizon, 26.5% Tax Rate
  - Debt to equity ratio consistent with 2024 cost of service filing[4] – ramps up to 58:42 in 2028, 4.65% cost of debt
  - In-service date: November 2024 & November 2025

Financial Outlook

in $MM	2022-23	2024	2025	2026	2027	2028	2029
Equity Cash Flow	2.8	(99.2)	(19.3)	7.9	8.8	9.4	15.7
EBITDA	-	7.2	4.8	21.4	23.1	24.5	29.3
Earnings	2.8	15.4	3.7	8.7	9.1	9.5	12.4
DCF	2.8	15.8	9.1	16.5	16.9	17.3	20.2
D/EBITDA		25.9x[2]	45.2x[2]	9.7x	8.6x	7.8x	6.4x
Annual ROE		130.5%[3]	3.6%[3]	6.2%[3]	6.5%[3]	6.8%[3]	9.1%

DCFROE	**9.2%**
EV/ 2026 EBITDA	16.8x
EV/ 2029 EBITDA	12.3x



Investment realizes a strong return from low-risk cost of service investment

[1] Assumption reflects the latest forecast of allowed ROE for EGI; [2] High D/EBITDA multiples in 2024 & 2025 due to the utilization of a full year's worth of tax depreciation, while generating 2 months worth of revenue from the 2024 and 2025 in-service capital; [3] Annual ROE is lower than the allowed ROE of 9.2% in years 2025-2028 due to the effects of levelized cost recovery. 2024 will be earning above the allowed ROE
[4] Should the debt to equity ratio remain at current levels at 64:36, the EBITDA would gradually decrease over the first 5 years over the introductory period, up to a maximum of ~$1.5M/year for 2029 onwards when compared to 58:42, with no impact to DCFROE

Recommendation

ENBRIDGE

Management recommends that the Board of Directors of Enbridge Inc. (the "Board") (a) take no exception to, and (b) defer to the Board of Directors of Enbridge Gas Inc. (the "Corporation") with respect to, the approval of the following:

- Increased funding for the Panhandle Regional Expansion Project, as revised (the "Project"), including the authority of the Corporation and the officers of the Corporation to take all such action, and to cause the subsidiaries of the Corporation to take all such action, necessary or advisable to effectuate the Project consistent with the project materials provided to the Board (the "Project Memo");

Management recommends that the Board approve funding for the Project, including:

- An additional capital appropriation of C$45 million for the Project, including AIDC, for an aggregate capital expenditure for the Project not to exceed C$359 million;
- A corresponding increase to the applicable budgets, to the extent necessary or appropriate; and
- Entry by Enbridge Inc. or its subsidiaries into such funding arrangements as may be required on terms as approved by the Executive Vice-President, Corporate Development, Chief Financial Officer & President, New Energy Technologies, or the Vice-President, Treasury, Risk & Pensions of Enbridge Inc.

Panhandle Regional Expansion Project
Alternatives Assessment – Summary
2023 Update for OEB Application

Why are incremental facilities required in Winter 2024/25?

Demand Forecast	Winter 22/23	Winter 23/24	Winter 24/25	Winter 25/26
Total System Demand	698	730	802	849
Incremental per Year	26	32	72	47
System Capacity (No Project)	737	737	737	737
Shortfall (No Project)	+38	+6	-112	-127

Based on the Winter 2024/2025 Panhandle System design forecast, a minimum of 69 TJ/d of incremental deliveries at Ojibway would be required to delay the in-service date of the proposed Project by one year (over triple the capacity which is operationally available to deliver to into Ojibway). This is larger than the forecast Panhandle System shortfall of 66 TJ/d because increasing deliveries at Ojibway will not efficiently serve the Leamington-Kingsville market demands.

Enhanced Target Energy Efficiency (ETEE)

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

From June 5, 2023 Report:

A maximum peak hour reduction potential of approximately 72,000 m3/hour (57 TJ/d) from general service customers could be obtained by Winter 2029/2030 and would cost approximately $468 million. This results in $8.2 million per TJ, whereas the preferred alternative provides capacity at a cost of $2.14 million per TJ.

Trucked CNG

A CNG analysis indicated that approximately 420 loads per day would be required to meet the shortfall capacity of 156 TJ/d on a Design Day. This alternative poses issues both in terms of logistics and in terms of security of supply. This alternative is not a viable solution and was not pursued further.

New LNG Plant

In the PRP proceeding, Enbridge Gas evaluated constructing and operating an LNG storage facility as an alternative. The estimated cost was $287 million (approximately $390 million in today's dollars) with about $5 million in annual operating expenses to address 106 TJ/d of system growth. This would only provide a portion of the capacity of the proposed Project. Enbridge Gas expects an LNG solution to require more significant investment in both the size of the facility required and annual operating expenses. Enbridge Gas expects the costs to be 50% to 80% more than the estimated costs from the PRP proceeding (upwards of $580 million) that addressed 156 TJ/d of system shortfall. As a result, Enbridge Gas deemed this alternative to be financially infeasible and did not assess it further.

Panhandle Regional Expansion Project
Alternatives Assessment – Summary
2023 Update for OEB Application

Analysis of PEPL Available Capacity

Annual	Winter
PEPL website at time of RFP showed 21 TJ/d 19 TJ/d was noted in Tenaska RFP bid Tenaska confirmed via follow-up that 21 TJ/d is available on a long term basis.	PEPL website does not show capacity for future years or winter No bids were received for Winter Only Service in the Enbridge RFP

On June 1, 2023, the PEPL website indicated that up to 21 TJ/d of delivery capacity was available at Ojibway. The available PEPL system capacity with delivery to Ojibway did not change since the RFP was conducted.

A firm exchange is not commercially available to defer the need for the proposed project to Winter 2025/26.

Estimated Costs of Ojibway Deliveries

		Estimated Annual Costs ($MM	
	Unit Cost (C/GJ/d)	21 TJ/d Delivery	42 TJ/d Delivery**
RFP Bid	0.55	$4.2	$8.4

Why is the NPS 36 the Preferred Alternative?

Potential Alternative	Incremental Capacity (TJ/d)	Cost ($ Million)	Net Present Value ($ 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 M 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.

Panhandle Regional Expansion Project
Alternatives Assessment – Summary
2023 Update for OEB Application

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

*The estimated O&M costs are based on the bid received in the RFP. The bid stated pricing is subject to refresh based on the market conditions at the time of contracting.

- Economic Feasibility:
  - ✓ Proposed Project provides the lowest cost per unit of capacity relative to all other alternatives assessed.

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

- Safety & Reliability:
  - ✓ Positions the Panhandle System and the distribution pipelines connecting to it to meet forecasted long-term growth in the most efficient manner.
  - ✓ Alleviates the largest bottleneck, increasing the reliability of service for existing customers and allowing for growth for both existing and new customers.

- Risk Management:
  - ✓ Increases price transparency of the Dawn Hub and Ontario customer’s access to diverse supply, and storage
  - ✓ Scalable with future system growth
  - ✓ Directly serves areas of growth

- Environmental and Socio-economic Impact:
  - ✓ Minimizes project impact by paralleling existing right of way

Additional Benefits of NPS 36 Loop vs NPS 30 Loop

Extending the existing NPS 36 pipeline from Dawn through to Comber Transmission at the same diameter will reduce overall system costs for operations and maintenance. A common pipe size benefits a system from a maintenance perspective in the reduced costs associated with two separate pipeline inspection program and minimizes the number of overall facilities therefore minimizing impacts to Indigenous peoples, municipalities, and landowners, and environmental; and costs to build and operate.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

Question:

Enbridge is currently coordinating its rebasing application for 2024. Please explain how this project relates (if at all) with rebasing.

Response

Please refer to Exhibit A, Tab 3, Schedule 1, Paragraph 13. /U

ENBRIDGE GAS INC.

Answer to Interrogatory from
Pollution Probe ("PP")

INTERROGATORY

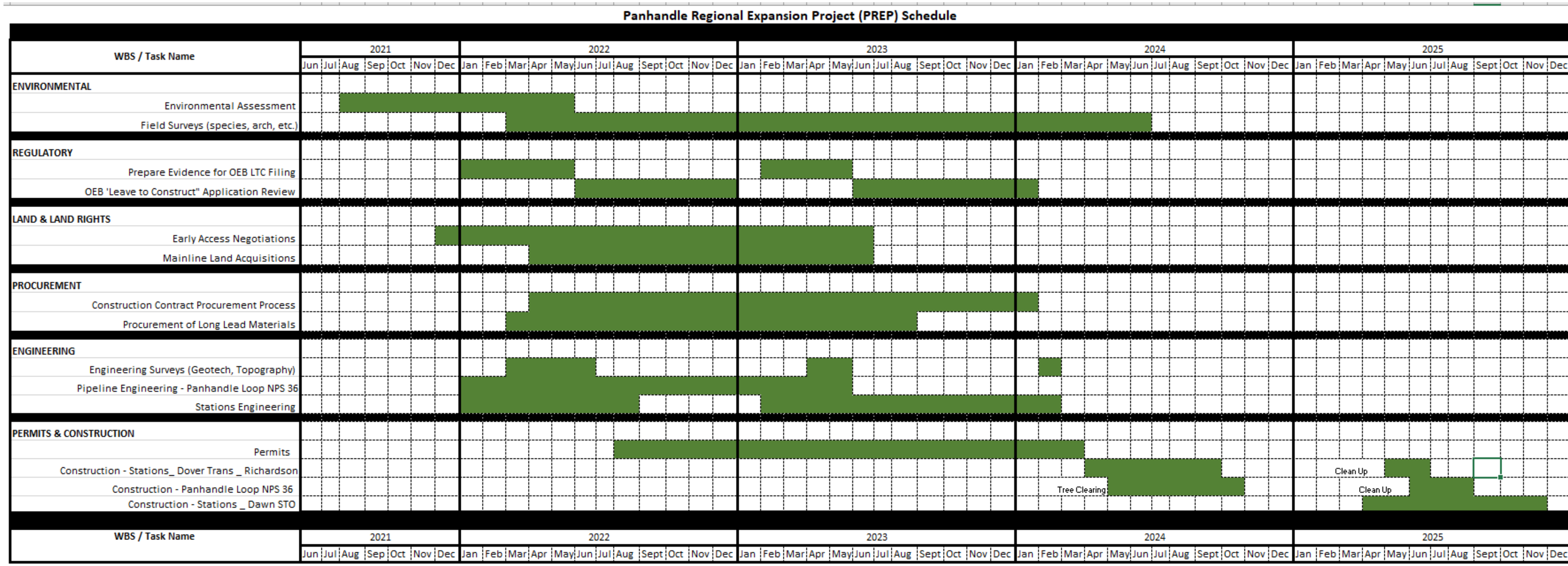
Question:

Please provide an updated project schedule including major milestones including permits and approvals.

Response

Please see Figure 1 below for an updated Project schedule.

Figure 1


Panhandle Regional Expansion Project (PREP) Schedule
WBS / Task Name
2021
2022
2023
2024
2025
Jun Jul Aug Sep Oct Nov Dec
Jan Feb Mar Apr May Jun Jul Aug Sept Oct Nov Dec
ENVIRONMENTAL
Environmental Assessment
Field Surveys (species, arch, etc.)
REGULATORY
Prepare Evidence for OEB LTC Filing
OEB 'Leave to Construct" Application Review
LAND & LAND RIGHTS
Early Access Negotiations
Mainline Land Acquisitions
PROCUREMENT
Construction Contract Procurement Process
Procurement of Long Lead Materials
ENGINEERING
Engineering Surveys (Geotech, Topography)
Pipeline Engineering - Panhandle Loop NPS 36
Stations Engineering
PERMITS & CONSTRUCTION
Permits
Construction - Stations_ Dover Trans _ Richardson
Construction - Panhandle Loop NPS 36
Construction - Stations _ Dawn STO
Tree Clearing
Clean Up
Clean Up

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, Attachment 1, page 5; Exhibit B, Tab 1, Schedule 1, page 11

Preamble:

Enbridge Gas stated that over 318 TJ/day of interest for incremental firm and interruptible demand over the 2023/2033 period from 44 customers was indicated through an Expression of Interest (EOI). Enbridge Gas provided a table showing its Panhandle Design Day demand forecast.

Question:

a) Please provide the annual results of the Expression of Interest in each of the three categories:
   i) new firm natural gas needs
   ii) conversion from interruptible distribution service to firm distribution service
   iii) new interruptible natural gas needs

b) Please describe how the results of the Expression of Interest have been incorporated into Enbridge Gas's Panhandle Design Day demand forecast; e.g., are 100% of the volumes from the first two categories in the EOI included within the demand forecast?

Response

/U

a) Please see Table 1 below.

Table 1

2023 Panhandle Regional Expansion Project EOI Bid Summary - by year (m3/hr)

	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	

Notes:
1) The volumes received through the 2023 Expression of Interest process were in cubic meters of gas per hour (m3/hr).
2) 71,262 m3/hr from the 2021 EOI has been contracted and is not included in the table above.
3) The 2023 Expression of Interest results, combined with the previously contracted volumes from the 2021 Expression of Interest process, were used to generate the revised demand forecast.

b) Please refer to note 3 in table 1 above /U

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, pages 18-19, paragraphs 55 and 56

Preamble:

Enbridge Gas stated that the capacity provided by the Project is intended to ensure the growing Panhandle Market has sufficient capacity until Winter 2028/2029.

In discussion of Project timing and growth plans, Enbridge Gas identified the potential need for a second phase of transmission expansion to meet the demands that are forecasted over the next 20 years. Enbridge Gas stated that it is forecasting the need for this second phase of transmission expansion to take place by Winter 2028/2029.

Question:

a) Please explain the rationale for the assertion that the Panhandle System with the proposed incremental capacity provided by the Panhandle Regional Expansion Project, subject to this application, will not be sufficient to provide the needed capacity to the Panhandle Market beyond Winter 2028/2029?

Response

a) Please refer to Table 1 showing the additional capacity added to Table 3 from Exhibit B, Tab 2, Schedule 1 on page 11. Assuming the Project is approved, the Panhandle System capacity of approximately 904 TJ/d compared to the forecast demands of approximately 906 TJ/d by Winter 2029/2030 would result in an estimated shortfall of 2 TJ/d (rounded). The forecasted demand is based on customer responses to the EOI process conducted in 2023 (Exhibit B, Tab 1, Schedule 1) and at Winter 2029/2030 total system demands would exceed system capacity. Enbridge Gas will continue to assess the Panhandle System's capacity position each year and at such time, evaluate if an IRP alternative could feasibly delay the need for further physical capacity. /U

Table 1: Panhandle System Capacity (following reinforcement), Design Day Demand and Shortfall

	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**	**725**	**713**	**737**	**737**	**904**	**904**	**904**	**904**	**904**	**904**	**904**
Design Day Demand Forecast (TJ/d)	**640**	**656**	**672**	**698**	**730**	**802**	**849**	**863**	**878**	**892**	**906**	**921**
Surplus (negative is shortfall)	84	69	41	38	6	102	55	41	26	12	(2)	(17)

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

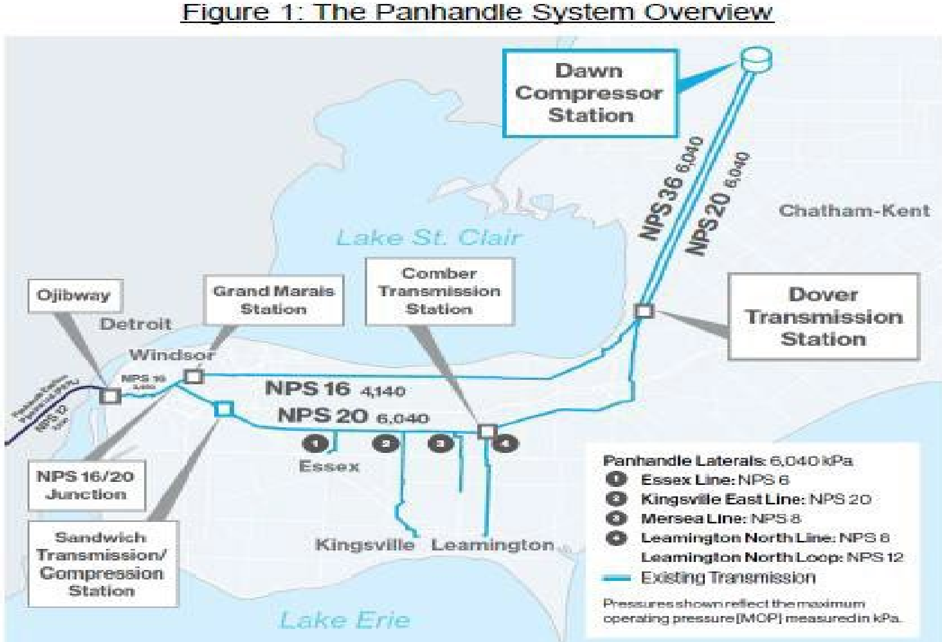
Reference:

Exhibit B, Tab 2, Schedule 1, Page 2, Figure 1: Panhandle System Overview; Exhibit C, Tab 1, Schedule 1, pages 1-25, Project Alternatives; Exhibit C, Tab 1, Schedule 1, page 9, Table 1: Summary of Current Panhandle System Pressure Bottleneck and Proposed Facility Solution

Preamble:

Enbridge Gas provided a diagram of the Panhandle System overview:

Figure 1: The Panhandle System Overview



Enbridge Gas identified two Panhandle System's pressure bottlenecks that need to be eliminated to provide the system capacity to meet the forecast demand growth:

1. The loss of pressure on NPS 20 Panhandle Line between Dover TS and Comber TS (Dover to Comber bottleneck)

2. The loss of pressure between NPS 20 Panhandle Line and Leamington-Kingsville market (Leamington-Kingsville market bottleneck)

The Project has been selected as a preferred alternative after assessment of:

1. Facility alternatives
   1. Panhandle Loop, to address the Dover to Comber bottleneck, construction of NPS 36 to loop (i.e. parallel to) the existing NPS 20 Panhandle Line west of Dover Transmission Station (TS).
      Leamington Interconnect, to address Leamington-Kingsville market bottleneck, construction of lateral NPS 16 connecting Kingsville East Line, Mersea Line, Leamington North Line and Leamington North Loop.
      The Panhandle Loop and Leamington Interconnect were selected as the best combined alternatives to meet the need determined by Enbridge Gas.
   2. Upsize of the existing NPS 16 Panhandle Line or NPS 20 Panhandle Line west of Dover TS
   3. Liquified Natural Gas (LNG) Plant

2. Integrated Resource Planning Alternatives (IRPA)
   1. Firm 3rd party exchange between Dawn and Ojibway
   2. Demand side management alternative: Enhanced Targeted Energy Efficiency (ETEE)
   3. Trucked Compressed Natural Gas (CNG)

3. Hybrid or combination of facility with IRPA alternative
   1. Firm exchange between Dawn and Ojibway combined with the looping of the existing NPS 20 Panhandle Line west of Dover TS and installing a Leamington Interconnect lateral NPS 16

Enbridge Gas stated that it employed the following criteria to assess and select the preferred alternative:

1. Economic criteria as a quantitative measure of cost-effectiveness and used the following metrics:
   1. Total cost
   2. Cost per unit of capacity
   3. Net Present Value (NPV)
2. Timing to meet the Panhandle System forecast demand within five years
3. Safety and reliability to provide reliable and safe delivery of firm volumes on the coldest winter day on the Panhandle System
4. Risk management defined as price risk increase once the alternative

has been deployed

5. Environmental and socio-economic impact which is defined by Enbridge Gas as qualitative impacts on Indigenous peoples, municipalities, landowners and the environment

Question:

a) Using the Panhandle System overview diagram please delineate the pipeline facilities alternatives discussed in the evidence. Please use a separate overview diagram for each of pipeline facilities alternatives considered to address the two system bottlenecks.
b) Please provide a table comparing all the alternatives assessed (facilities, IRPA and Hybrid) including the proposed Project. For each alternative provide values (quantitative or qualitative) of the five assessment criteria noted in the evidence. In a separate column explain the rationale for the outcome of the assessment for each of the alternatives.

Response

a) Please see Figures 1-8 below for diagrams of each of the Facility, IRPA and Hybrid alternatives discussed. These diagrams have been updated to reflect the alternatives with the removal of the Leamington Interconnect where applicable.

Facility Alternative Maps

Figure 1

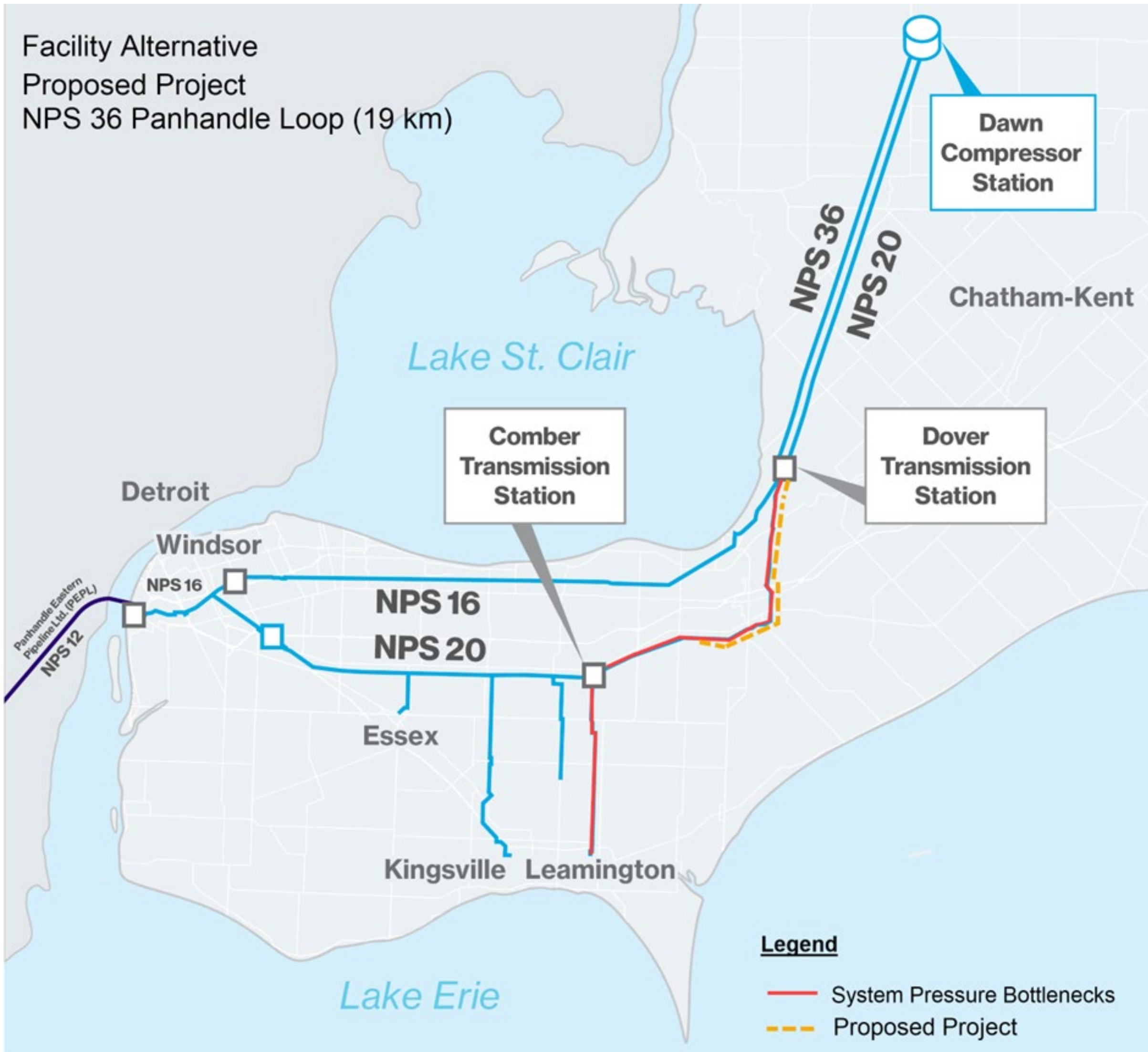


Figure 2

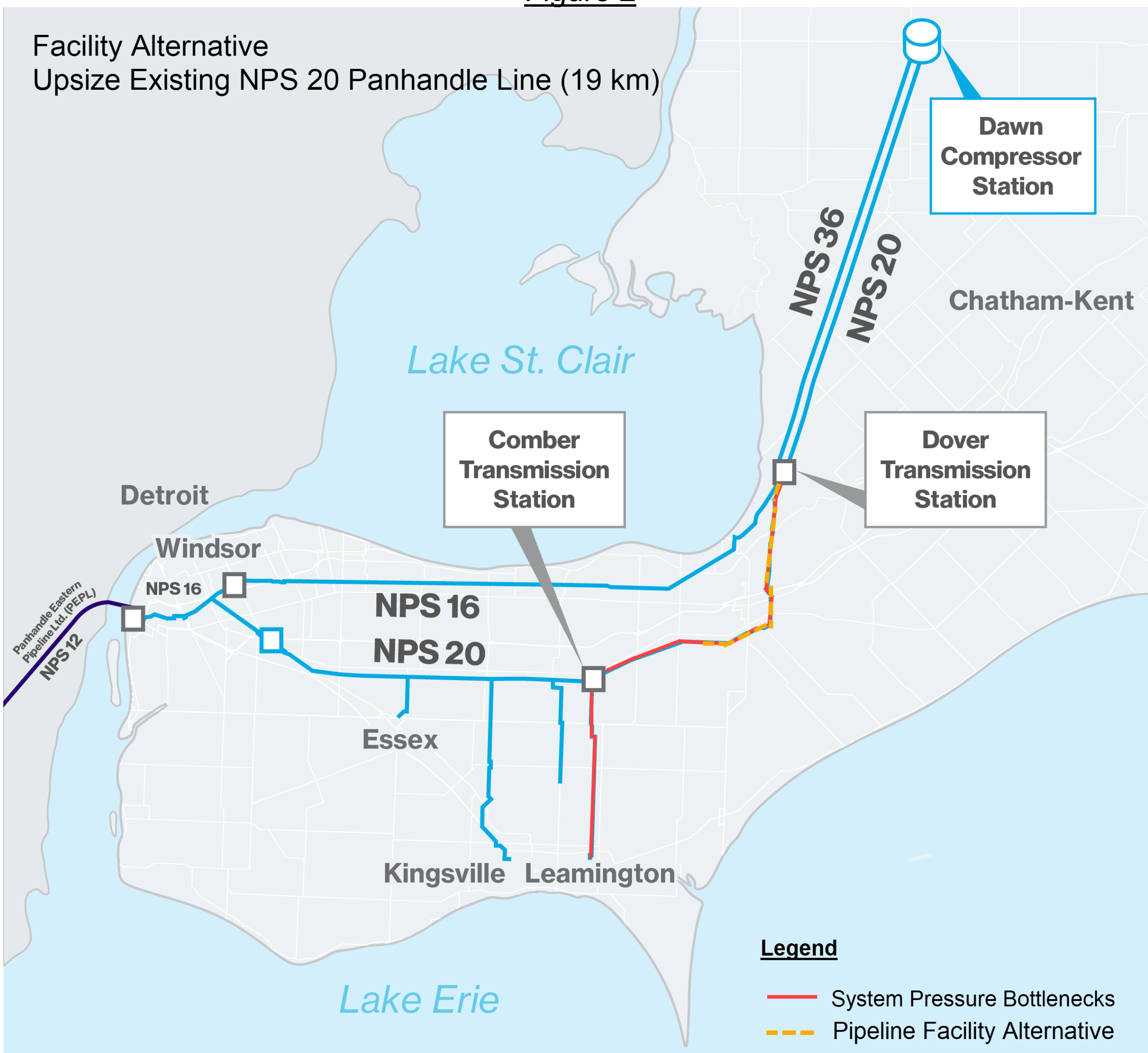


Figure 3

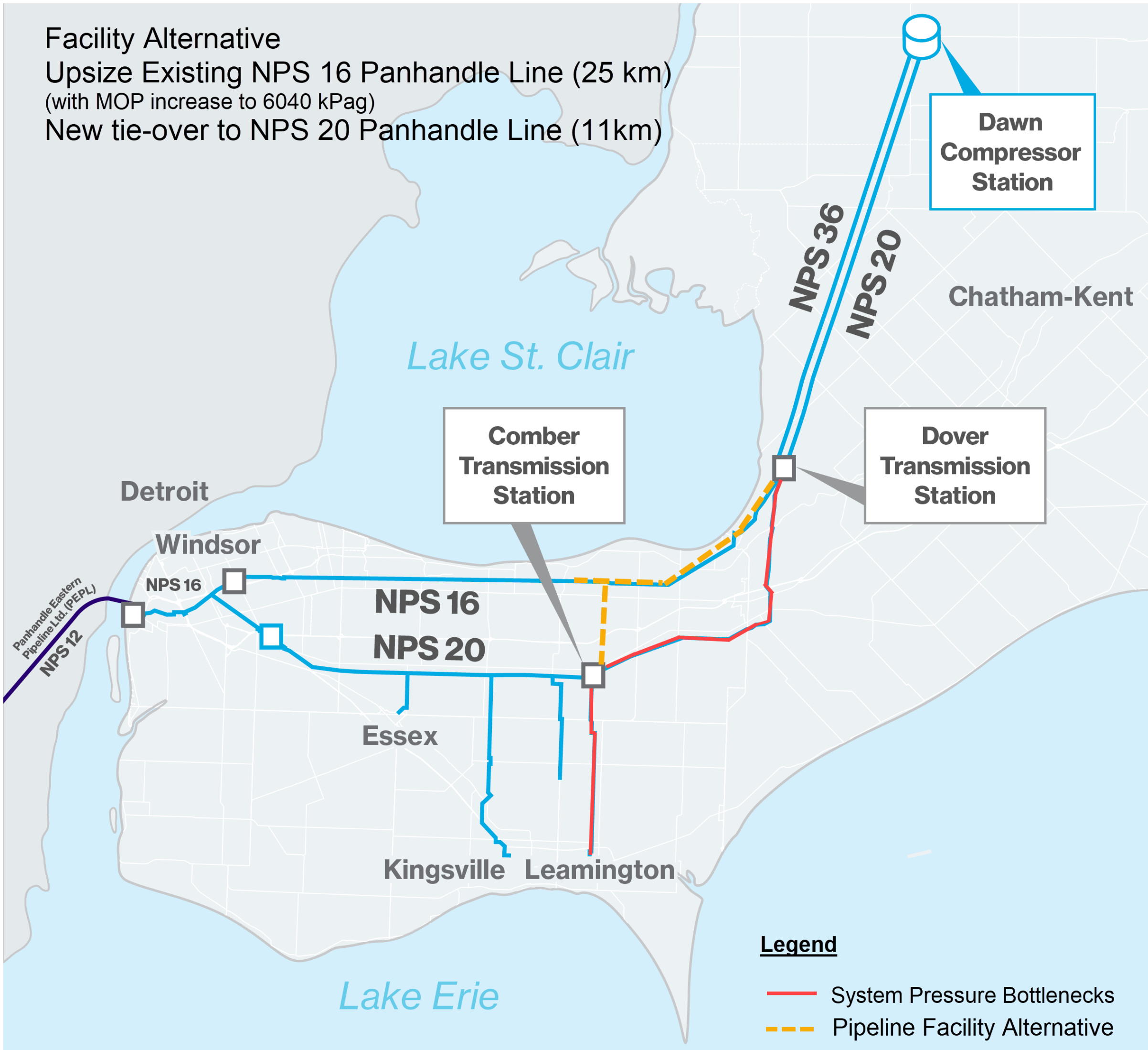
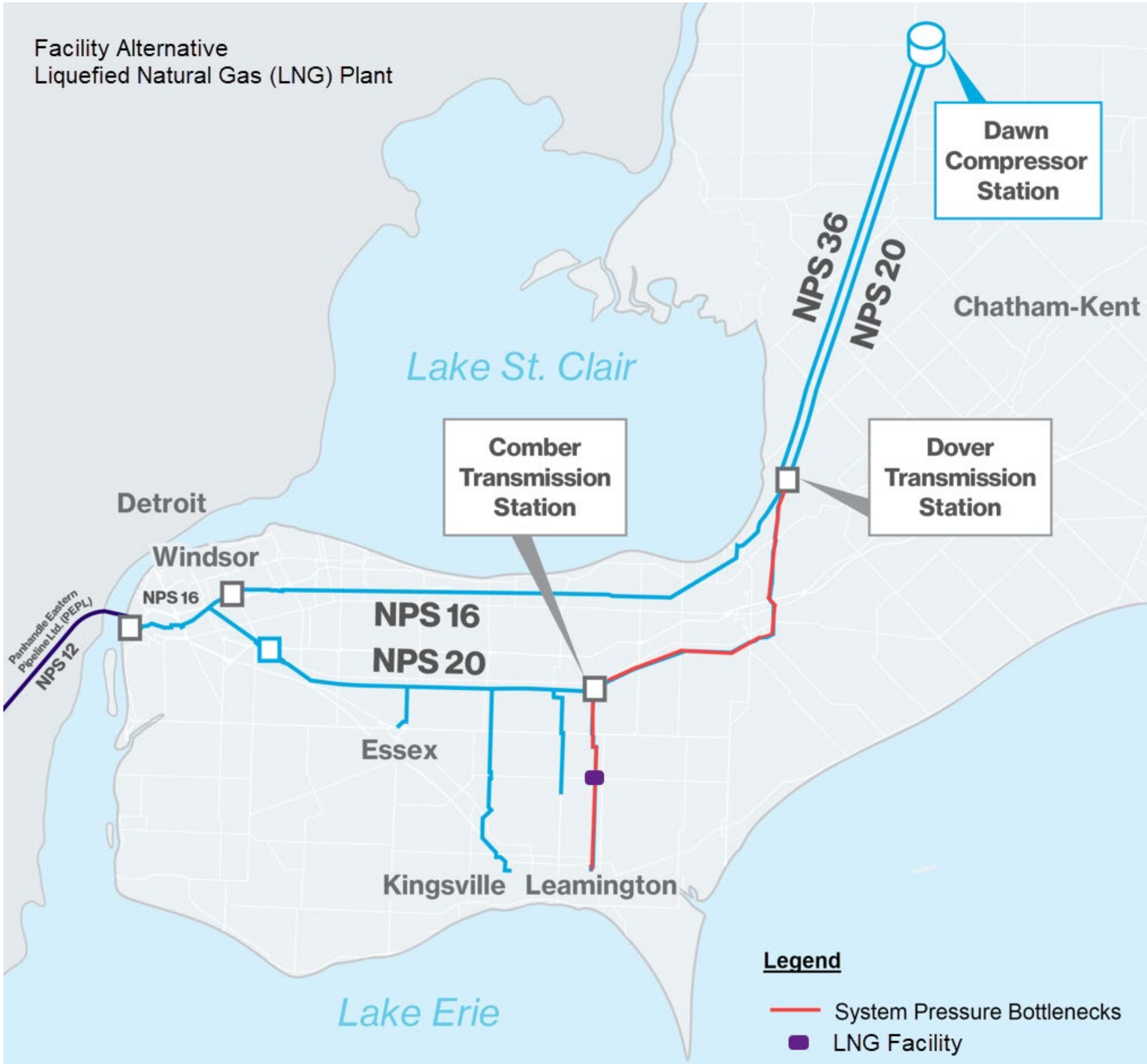

Facility Alternative
Upsize Existing NPS 16 Panhandle Line (25 km)
(with MOP increase to 6040 kPag)
New tie-over to NPS 20 Panhandle Line (11km)
Dawn Compressor Station
NPS 36
NPS 20
Chatham-Kent
Lake St. Clair
Comber Transmission Station
Dover Transmission Station
Detroit
Windsor
NPS 16
Panhandle Eastern Pipeline Ltd. (PEPL)
NPS 12
NPS 16
NPS 20
Essex
Kingsville
Leamington
Lake Erie
Legend
System Pressure Bottlenecks
Pipeline Facility Alternative

Figure 4


Facility Alternative
Liquefied Natural Gas (LNG) Plant
Dawn Compressor Station
NPS 36
NPS 20
Chatham-Kent
Lake St. Clair
Comber Transmission Station
Dover Transmission Station
Detroit
Windsor
NPS 16
Panhandle Eastern Pipeline Ltd. (PEPL)
NPS 12
NPS 16
NPS 20
Essex
Kingsville
Leamington
Lake Erie
Legend
System Pressure Bottlenecks
LNG Facility

Integrated Resource Planning Alternatives

Figure 5

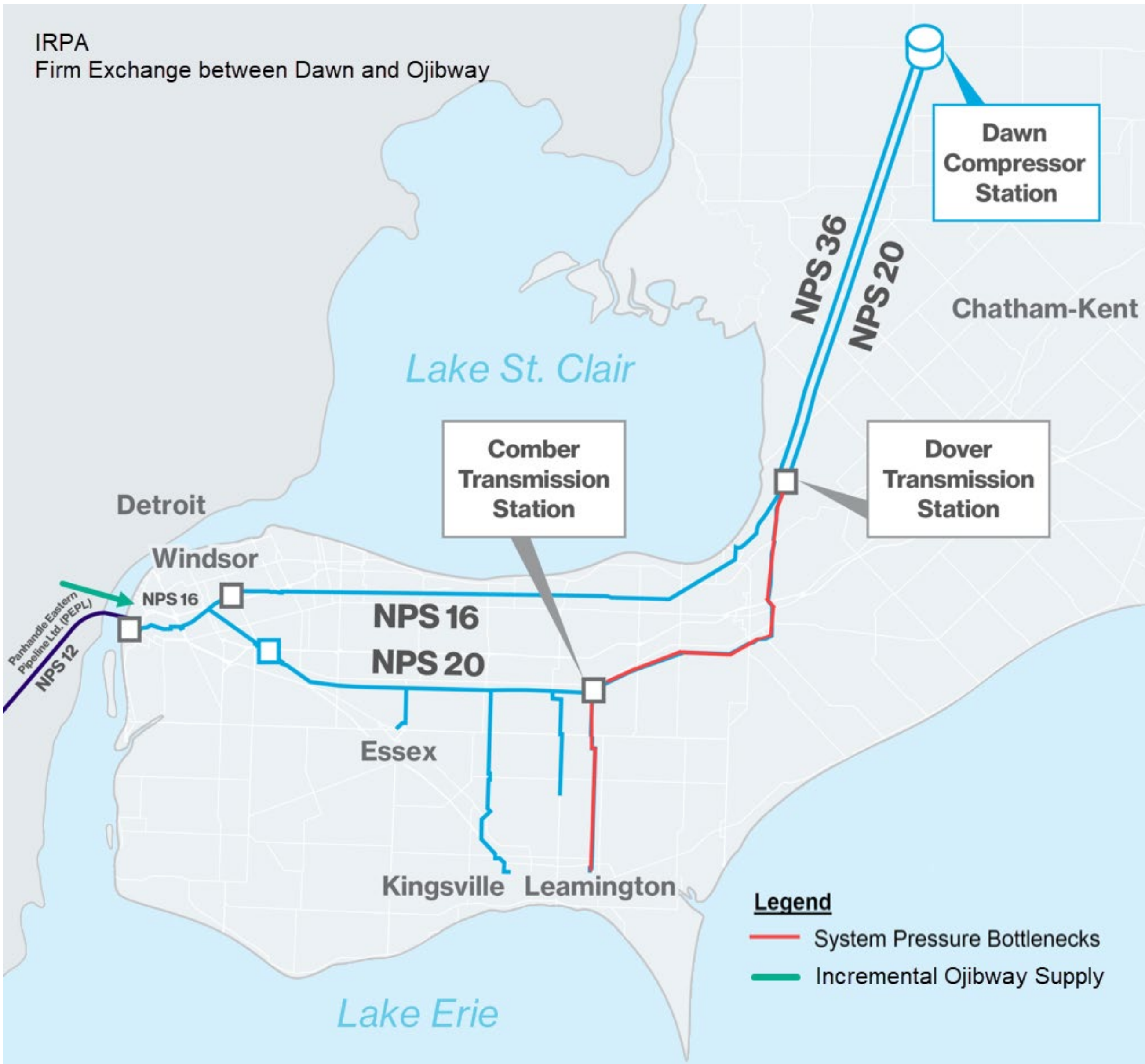


Figure 6

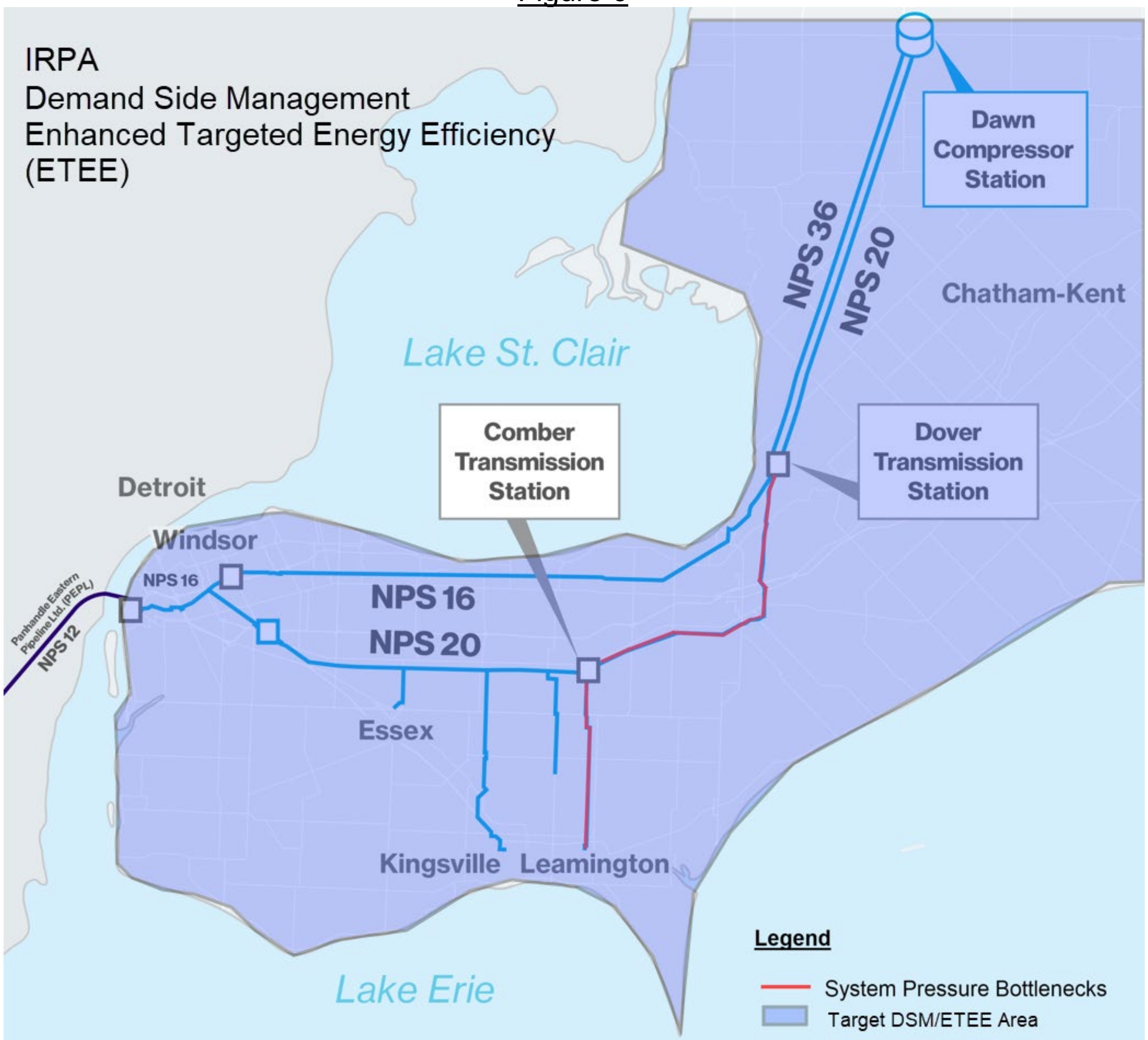
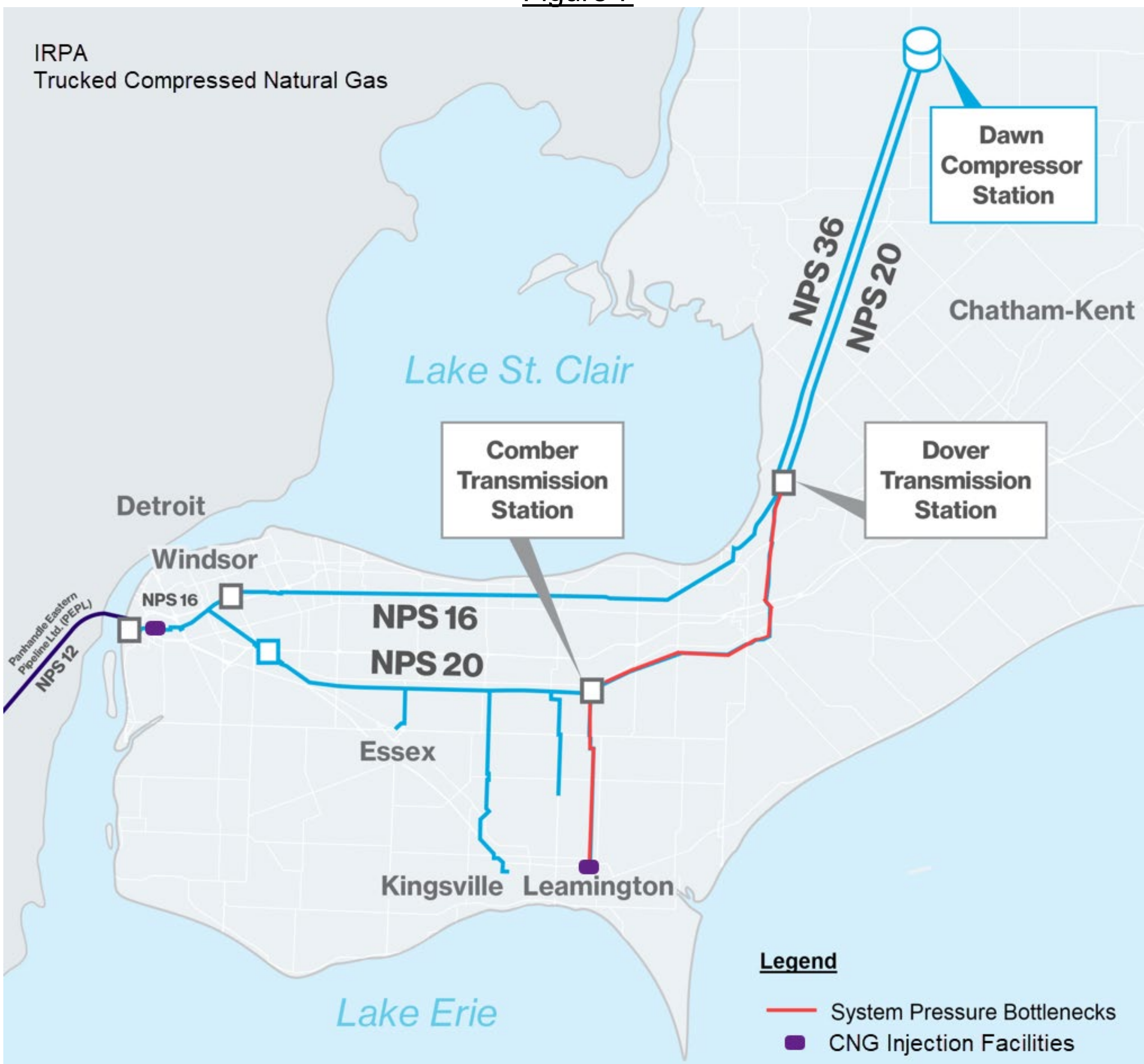
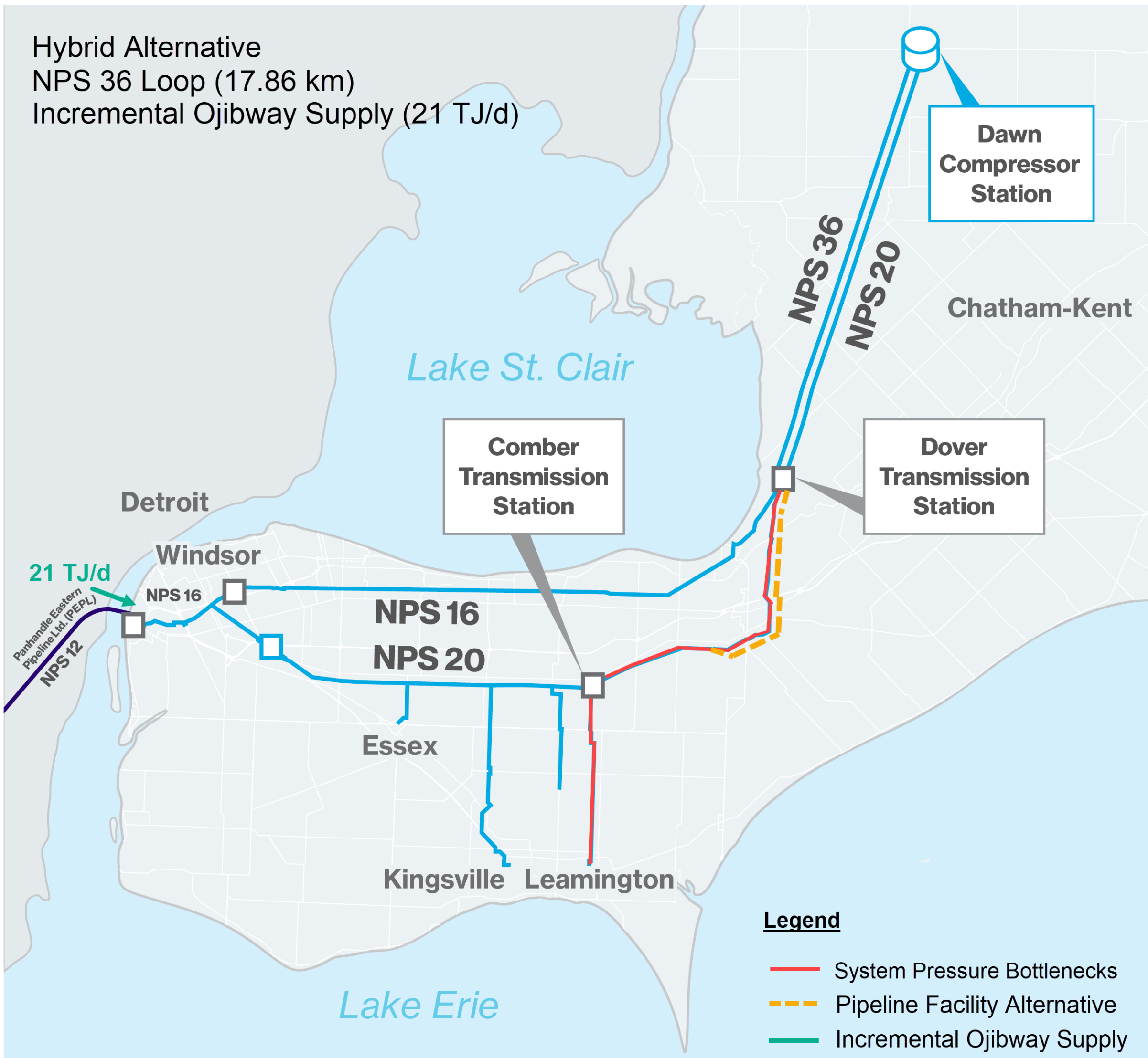

IRPA
Demand Side Management
Enhanced Targeted Energy Efficiency
(ETEE)
Dawn Compressor Station
NPS 36
NPS 20
Chatham-Kent
Lake St. Clair
Comber Transmission Station
Dover Transmission Station
Detroit
Windsor
NPS 16
Panhandle Eastern Pipeline Ltd. (PEPL)
NPS 12
NPS 16
NPS 20
Essex
Kingsville
Leamington
Lake Erie
Legend
System Pressure Bottlenecks
Target DSM/ETEE Area

Figure 7


IRPA
Trucked Compressed Natural Gas
Dawn Compressor Station
NPS 36
NPS 20
Chatham-Kent
Lake St. Clair
Comber Transmission Station
Dover Transmission Station
Detroit
Windsor
NPS 16
Panhandle Eastern Pipeline Ltd. (PEPL)
NPS 12
NPS 16
NPS 20
Essex
Kingsville
Leamington
Lake Erie
Legend
System Pressure Bottlenecks
CNG Injection Facilities

<u>Hybrid Alternative</u>

<u>Figure 8</u>



b) For a summary of viable alternatives (i.e., alternatives that meet all Assessment Criteria), please see Attachment 1 to this response. For a summary of non-viable alternatives (i.e., alternatives that do not meet all Assessment Criteria) please see Attachment 2 to this response. The Assessment Criteria applied to all alternatives is discussed at Exhibit C, Tab 1, Schedule 1, Pages 3-4.

Viable Alternatives (Meets all Alternatives Assessment Criteria)

Viable Alternative Description	Type	Capacity Created (TJ/d)	Cost Effectiveness			Timing	Safety & Reliability	Risk Management	Environmental & Socio-economic	Rationale
			Total Cost ($ million)	$/TJ	NPV[1]					
Proposed Project 19 km NPS 36 Panhandle Loop	Facility	168	$358.0	$2.13	$(153.5)	✓	✓	✓	Minimizes project impact by paralleling existing right-of-way	Most cost-effective alternative with best cost per unit of capacity. The proposed Project includes a larger capacity, with a lower cost per unit of capacity, to more effectively meet the growing customer demands. Please also see the response at Exhibit I.EP.8 for discussion of long-term benefits of this alternative.
19 km of NPS 30 Panhandle Loop	Facility	160	$342.7[2]	$2.14	$(144.6)	✓	✓	✓	Minimizes project impact by paralleling existing right-of-way	Creates less capacity (168 TJ vs. 160 TJ) and is therefore less cost effective based on cost per unit of capacity ($2.14 vs. $2.13 for the proposed project. Provides a slightly higher NPV then the proposed project but limited ability to serve anticipated future system demand.
17.86 km NPS 36 Panhandle Loop 21 TJ/d Firm Exchange between Dawn and Ojibway	Hybrid #1	168	Facility $351.0 <u>O&M</u> $4.2 Annually $(66.2) over a 40-year term[3]	$2.48	$(212.1)	✓	✓	✓	Minimizes project impact by paralleling existing right-of-way	More costly than the preferred alternative based on cost per unit of capacity ($2.48 vs. $2.13 for the proposed Project) and NPV [$(212.1) vs. $(153.5) for the proposed Project)] due to the need for both facilities and incremental annual O&M costs for a firm exchange service. There is future price risk with respect to exchange services. The service contains price variability compared to facility alternatives which have a fixed cost once installed.
16.20 km NPS 36 (Wheatley Road end-point) 21 TJ/d Firm Exchange between Dawn and Ojibway	Hybrid #2	153	Facility $330.5 <u>O&M</u> $4.2 Annually $(66.2) over a 40-year term[3]	$2.59	$(204.0)	✓	✓	✓	Minimizes project impact by paralleling existing right-of-way	More costly than the preferred alternative based on cost per unit of capacity ($2.59 vs. $2.13 for the proposed Project) and NPV [$(204.0) vs. $(153.5) for the proposed Project)] due to the need for both facilities and incremental annual O&M costs for a firm exchange service. There is future price risk with respect to exchange services. The service contains price variability compared to facility alternatives which have a fixed cost once installed.

[1] The calculation of the Net Present value does not include Overheads.

[2] The estimated cost of $342.7 M 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.

[3] The estimated O&M costs are based on the bid received in the RFP. The bid stated pricing is subject to refresh based on the market conditions at the timing of contracting.

Viable Alternatives (Meets all Alternatives Assessment Criteria)

Viable Alternative Description	Provides market assurance in meeting the growing firm demands along the Panhandle System for the next five years.	Increases Ontario customers' access to diverse supply, storage, and price transparency of the Dawn Hub.	Scalable with system growth.	Directly feeds area of growth.
Proposed Project 19 km NPS 36 Panhandle Loop	✓	✓	✓	✓
19 km NPS 30 Panhandle Loop	✓	✓	✓	✓
17.86 km NPS 36 Panhandle Loop 21 TJ/d Firm Exchange between Dawn and Ojibway	✓	✓	✓	✓
16.20 km NPS 36 (Wheatley Road end-point) 21 TJ/d Firm Exchange between Dawn and Ojibway	✓	✓	✓	✓

Non-Viable Alternatives (Does not meet all the Alternatives Criteria)

Non-Viable Alternative Description	Type	System Capacity Created (TJ/d)	Cost Effectiveness	Timing	Safety & Reliability	Risk Management	Environmental & Socio-economic	Rationale
Upsize of existing NPS 16 Panhandle Line west of Dover Transmission	Facility	N/A	N/A	X	X	✓	Easements on previously undisturbed land	This Alternative is not viable as it cannot be constructed for November 1, 2024 and maintain reliable service to Panhandle System customers. This alternative would require moving as many as nine downstream system connections from the NPS 16 Panhandle Line to the NPS 20 Panhandle Line and constructing a new interconnecting pipeline between the NPS 16 Panhandle Line and the NPS 20 Panhandle Line. Additionally, this alternative would require acquisition and development of new greenfield pipeline easements on previously undisturbed land resulting in increased environmental and landowner impacts compared to the proposed Project.
Upsize of existing NPS 20 Panhandle Line west of Dover Transmission	Facility	N/A	N/A	X	X	✓	Minimizes project impact by paralleling existing right-of-way	The NPS 20 Panhandle Line is required to serve customers at all times of the year because the NPS 16 Panhandle Line cannot serve system demands on its own, even during periods of low demand in the summer. As result, reliable service to customers could not be maintained during the construction period while the NPS 20 Panhandle Line would be out of service. Therefore, a lift and lay of the NPS 20 Panhandle Line west of Dover Transmission is not a viable alternative.
Liquefied Natural Gas (LNG) Plant	Facility	~156 TJ/d	Costs: ~$580 million in today's dollars O&M: $5 million annually	X	✓	✓	N/A	This alternative cannot be constructed for Winter 2024/25 and does not meet timing criteria. Additionally, this alternative is not financially feasible therefore Enbridge Gas did not assess it further.
Firm 3rd party exchange between Dawn and Ojibway (+21 TJ/d, maximum available)	IRPa	Please Refer to Exhibit I.ED.6a(i)	IRPA Costs: $4.2 million Annually, 66.2 over a 40-year term[1] $/Capacity: $3.15	X	✓	✓	Utilizes existing pipeline facilities	A firm exchange service between Dawn and Ojibway was rejected as there are no stand-alone commercial services that can be contracted with a pipeline company or secondary market that would deliver gas via the Panhandle System into the distribution networks that would eliminate the need for additional facilities. It is not possible to address the 5-year system shortfall of 156 TJ/d with Ojibway deliveries alone because the volume required would greatly exceed the physical import capability at Ojibway. Based on the Winter 2024/25 Panhandle System design forecast, a minimum of 69 TJ/d of incremental deliveries at Ojibway would be required to delay the in-service date of the proposed Project by one year (over triple the capacity which is operationally available to deliver to into Ojibway). This is not commercially available, as the estimated available capacity on the Panhandle Eastern Pipeline system with delivery to Ojibway is 21 TJ/d based on results from RFP.

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

Non-Viable Alternatives (Does not meet all the Alternatives Criteria)

Demand side management alternative: Enhanced Targeted Energy Efficiency (ETEE)	IRPA	57 TJ/d	Costs: ~$468 million $/Capacity: $8.2	X	✓	✓	✓	As noted in the Posterity report included at Attachment 3to Exhibit C-1-1, a maximum peak hour reduction potential of 72,000 m^3/hour (57 TJ/d) from general service could be obtained by 2029/2030 compared to 168 TJ/d from the proposed project. There is insufficient peak demand reduction potential from the general service customer base downstream of the Leamington lateral interconnect to eliminate or reduce the scope of facility requirements to meet the identified system need.
Trucked Compressed Natural Gas (CNG)	IRPA	N/A	N/A	X	X	X	X	Approximately 420 truckloads of CNG per day would be required to meet the shortfall capacity of 156 TJ/d. This is not practical and poses issues both in terms of logistics and security of supply. For these reasons Enbridge Gas determined that this alternative is not a viable solution early in its assessment of alternatives and did not pursue further.

Non-Viable Alternatives (Does not meet all the Alternatives Criteria)

Non-Viable Alternative Description	Provides market assurance in meeting the growing firm demands along the Panhandle System for the next five years.	Increases Ontario customers' access to diverse supply, storage, and price transparency of the Dawn Hub.	Scalable with system growth.	Directly feeds area of growth.
Upsize of existing NPS 16 Panhandle Line west of Dover Transmission	✓	✓	✗	✗
Upsize of existing NPS 20 Panhandle Line west of Dover Transmission	✓	✓	✓	✓
Liquefied Natural Gas (LNG) Plant	✓	✓	✓	✓
Firm 3rd party exchange between Dawn and Ojibway (+21 TJ/d, maximum available)	✗	✗	✗	✓
Demand side management alternative: Enhanced Targeted Energy Efficiency (ETEE)	✗	✗	✓	✓
Trucked Compressed Natural Gas (CNG)	✓	✓	✓	✓

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit A, Tab 2, Sched 2, page 2; Exhibit B, Tab 1, Sched 1, page 18

Preamble:

Enbridge Gas noted that the capacity provided by the Project is intended to ensure the growing Panhandle Market has sufficient capacity until Winter 2028/2029. Enbridge Gas indicated that it has also identified the potential need for a second phase of transmission expansion to meet the demands that are forecasted over the next 20 years, with a forecasted 2029 in-service date.

Question:

a) Please clarify why Enbridge Gas proposed sizing the Project specifically to provide incremental capacity to address a five-year forecasted shortfall (i.e. as opposed to a smaller or larger project that would address the shortfall for a shorter or longer time horizon, respectively).
b) Did Enbridge consider a project alternative (e.g. increasing the pipeline sizes of the Project) that would avoid the need for a second phase of expansion? If so, please describe why Enbridge Gas rejected this option, with reference to factors (e.g., cost per unit capacity/NPV, demand forecast uncertainty, etc.) that contributed to Enbridge Gas's decision.

Response

a) As discussed at Exhibit C, Tab 1, Schedule 1, the proposed Project is the most cost-effective alternative on a cost per unit of capacity basis and is capable of serving forecasted demand until Winter 2028/2029. Other Project benefits are discussed in the response at Exhibit I.EP.8. /U

Enbridge Gas designed the proposed Project to address the five-year forecast shortfall, while providing a balance between cost efficiencies in the planning, development, construction of the Project, and the forecast variability in the later years of the forecast. The proposed Project provides market assurance in meeting the growing firm demands along the Panhandle System for the next five years.

b) Yes. Enbridge Gas considered alternatives including increased pipeline diameter. The NPS 42 Panhandle looping of the NPS 20 Panhandle Line option was not selected as the preferred alternative for several reasons: /U

- It only provides 4 TJ/d of additional capacity compared to the NPS 36, because the NPS 20 Panhandle Line bottleneck beyond the proposed Project end point to Comber Transmission station is not alleviated.
- It is not a consistent pipe size with the upstream NPS 36 pipeline between Dawn and Dover Transmission station.
- There are increased costs due to the additional launcher and receiver facilities required for the integrity program; and,
- It requires two separate integrity programs, introducing additional risk, cost, and gas handling complexity into the operation and maintenance of the Panhandle System.

For a summary of all viable pipeline facility alternatives, please see Attachment 1 at Exhibit I.STAFF.7.

In order to mitigate the capacity shortfall beyond Winter 2028/2029, the various pipeline facilities considered would need to be extended towards Comber Transmission station to increase system capacity and reduce or eliminate the system bottlenecks downstream of the proposed Project.

It is not possible to avoid the need for future facilities beyond Winter 2028/2029 by increasing the diameter of any of the viable pipeline alternatives. Please see the response to Exhibit I.SEC.4 part a), which explains the 5-year timing criterion (the Project is expected to be fully utilized by 2029). Supporting 5 years of forecast growth strikes an ideal balance between meeting near term demands with a high level of certainty, cost efficiencies in the planning, development and construction of facilities required, and flexibility to adjust the growth forecast with the best available information in the future.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B, Tab 1, Schedule 1, pages 8-9; IRP Decision and Order (EB- 2020-0091), page 94

Preamble:

Enbridge Gas noted that it has not received any interest from customers in turning back firm or interruptible capacity or converting existing firm capacity to interruptible capacity.

Question:

a) Please provide a status update on the scope and timing of Enbridge Gas's efforts in response to the OEB's direction in the IRP Decision and Order to study how interruptible rates might be modified to increase customer adoption in order to help reduce peak demand.

b) Is Enbridge Gas giving consideration to demand response Integrated Resource Planning Alternatives (IRPAs) for customers (contract or general service) on firm distribution service, either as:
    i. an alternative to the proposed Project. Please describe any such alternative assessed.
    ii. to avoid or defer the potential second phase of transmission expansion beyond 2028/2029 in this region? If so, please describe. If not, why not?

Response

a) Enbridge Gas filed the interruptible rates study in its 2024 Rate Rebasing proceeding (EB-2022-0200) at Exhibit 8, Tab 4, Schedule 7 and expects an OEB Decision on the proposal in Q4 2023 or Q1 2024. /U b)

i) Yes, Enbridge Gas did consider demand response as an IRP alternative to the Project. Specifically, Enbridge Gas offered contract customers the opportunity to replace firm services with interruptible services, and inquired whether customers would be more inclined to consider interruptible services if the opportunity to negotiate lower than posted interruptible rates was available. As described in Exhibit B, Tab 1, Schedule 1, Paragraph 28, only 2 bids or 3% of the total EOI interest indicated that interruptible services was a viable alternative. Further, only 5 bids or 8% of the total EOI interest (inclusive of the two bids mentioned above) indicated they would consider interruptible service as an alternative to firm service, with a required reduction ranging between 20% and 35% below current interruptible rates. Of those five bids, three bids indicated that interruptible service was not a viable option and did not specify how they would comply during an interruption event. These five bids were not significant enough to reduce or defer the scope of the Project See Exhibit A Tab 4 Schedule 1 Page 4 Paragraph 17. /U

ii)

Most of the large customers in the Project area cannot shift their natural gas demands to off peak times or have their firm natural gas demands interrupted. Many of the customers in the Project area operate greenhouses and cannot shift their natural gas demands to off peak times, as this would result in no heat in the greenhouse during peak periods, which could damage their crops. Aside from natural gas, the main alternate fuels used for heating in the greenhouse sector are oil, diesel and propane. Not only are these fuels typically more expensive than natural gas, but they would also prevent a greenhouse from using the CO2 emissions within the greenhouse because other elements in the exhaust of those alternate fuels would harm the crops. Without the availability of natural gas, a more expensive and higher carbon intensive energy source would need to be procured for heat, and an alternative source of CO2 would also be required to maintain production levels. Backup alternate fuel systems are also not intended or designed to be used for extended periods of time. The availability of alternate fuels is another concern. In general, switching fuel sources is disruptive for greenhouse operations.

There are also commercial, industrial, and power generation customers within the Project area for which a demand response, or interruptible service, is not a viable option, as a reduction in natural demand consumption would cause a disruption to operations, creating economic and productivity loss, uncertainty, as well as potential safety concerns for processes that cannot be easily/safely shut down and restarted at great frequency.

iii) Please see the response at Exhibit I.STAFF.10 b).

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit E, Tab 1, Schedule 1, pages 4-10; Exhibit E, Tab 1, Schedules 3-7.

Preamble:

Enbridge Gas noted that E.B.O. 134 is the appropriate economic test to apply to the Project, as the Project consists entirely of transmission pipeline infrastructure to which distribution customers do not directly connect.

Enbridge Gas noted that the Stage 1 Discounted Cash Flow (DCF) analysis for the Project shows that the Project has a Net Present Value (NPV) of negative $95 million and a Profitability Index (PI) of 0.63. Enbridge Gas further noted that after the Stages 2 and 3 DCF analyses are applied, the NPV for the Project is between $342 million and $463 million, and the Project is economically feasible.

Question:

a) Please explain why indirect overhead is not included as part of the cash outflows in the DCF analysis. As part of the response, please provide a reference the E.B.O. 134 Report of the Board.

b) Please discuss the contract demand for contract rate customers and volumes for general service customers used in the calculation of the transmission margin at Exhibit E, Tab 1, Schedule 4. Please explain how these contract demand and volume figures were derived. Further, please explain how these figures align with the statement that 98% of the incremental capacity created by the Project will meet contract rate customer demand.

c) Please provide a detailed calculation supporting the Stage 2 DCF analysis at Exhibit E, Tab 1, Schedule 6.
   i. Please explain the annual energy demand figure used in the Stage 2 DCF

analysis. Specifically, please discuss this energy demand figure in the context that it appears that only 2% of the incremental capacity created by the Project is for general service customers.

ii. Please explain how the fuel mix used in the Stage 2 DCF analysis was estimated.

iii. Please explain the $0.14/m^3 price for natural gas used in the Stage 2 DCF analysis.

iv. Please confirm that the natural gas price used in the Stage 2 DCF analysis includes the cost of carbon.

d) Please confirm that only the direct economic benefits associated with the Project are included in the Stage 3 DCF analysis at Exhibit E, Tab 1, Schedule 7.

e) Please explain the GDP Factor and the Jobs Factor used in the Stage 3 DCF analysis.

f) Please confirm that the economic benefits (e.g. GDP impact, taxes, etc.) listed in the Stage 3 DCF analysis are the same as used in previous E.B.O. 134 tests for OEB approved Panhandle projects. If there are any changes relative to previous applications for Panhandle projects, please explain those changes and provide rationale supporting the changes.

<u>Response</u>

a) E.B.O. 134 Report of the Board states "The Board finds that incremental costs should be used in evaluating the feasibility of system expansion."[1] Indirect overhead is not an incremental cost and has therefore not been included in the DCF analysis.

b) The contract demand for contract rate customers was derived by dividing the Contract Firm (Total Incremental Demand) forecast, as seen at Exhibit B, Tab 1, Schedule 1, Page 13, Table 2, by a heat value content of 0.03932 GJ per m^3. /U

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[1] Ontario Energy Board, E.B.O. 134 Report of the Board, June 1, 1987, paragraph 6.70

The volumes for general service customers were derived using Enbridge Gas's customer attachment forecast. The customer attachments are converted into an annual volumetric forecast based on a forecast normalized average consumption.

Enbridge Gas's pipeline systems are designed to serve the peak design day demands of natural gas consumers. The schedule referred to by OEB Staff (Exhibit E, Tab 1, Schedule 4) is the Calculation of Revenue for the Project, which is calculated based on annual volumes/demand. There is no direct correlation between annual demand (m^3) and peak day demand (TJ/d) as each are highly dependent on temperature and individual customer demand profiles. In other words, the revenue forecast for the Project provided at Exhibit E, Tab 1, Schedule 4 cannot be compared to the statement that 94% of Project capacity is designed for contract rate customer demand at Exhibit B, Tab 1, Schedule 1, Paragraph 33, as the annual demand that underpins the Calculation of Revenue for the Project is not related to the peak design day demand.

c) Please refer to Exhibit I.ED.14 Attachment 1 for a live Excel version of the calculation. /U

i. The statement that 2% of the incremental capacity created by the Project is for general service customers is based on the Design Day Demand forecast as shown at Exhibit B, Tab 1, Schedule 1, Page 13, Table 2 (TJ/d). The Stage 2 energy demand figure is based upon the forecast annual energy provided to general service customers by the Project. Please also see the response to part b) above.

ii. The fuel mix used in the Stage 2 analysis is based upon the Statistics Canada report Households and the Environment: Energy Use.[2] The fuel mix was calculated assuming the exclusion of natural gas and wood from the Stats Canada data.

iii. The natural gas price has been updated to $0.30/m³. The updated price is the average effective price for the 12 months ending March 2023 determined using the posted effective price from the Ontario Energy Board website.[3] See Table 1 below.

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[2] Statistics Canada Catalogue no. 11-526-S, Households and the Environment: Energy Use - 2011, Page 19, Table 2
[3] https://www.oeb.ca/consumer-information-and-protection/natural-gas-rates/historical-natural-gas-rates

Table 1: Average Effective Price of Natural Gas

Date	Effective Price (¢/m^3)
Apr 2022	20.1518
Jul 2022	31.3751
Oct 2022	36.0910
Jan 2023	32.3821
Average	**30.0000**

iv. The natural gas price of $0.30/$m^3$ is a before cost of carbon price, however the cost of carbon has been included separately in the results of the Stage 2 analysis.

d) Confirmed. Only economic benefits associated with the Project are included in the Stage 3 analysis.

e) The GDP Factor and Jobs Factor quantifies the impact that infrastructure spending has on gross domestic product (“GDP”) and on the generation of jobs. The GDP factor of 0.91 indicates that GDP rises by $0.91 per dollar of spending. The Jobs factor of 4.7 indicates that 4.7 jobs are generated per million dollars spent.

f) Confirmed. The approach to economic benefits in the Stage 3 analysis are the same as used in previous OEB-approved Panhandle projects. The assumption figures for GDP and Jobs Factors have been updated in this analysis to reflect more current information (see footnote at Exhibit E, Tab 1, Schedule 7 for source).

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit F, Tab 1, Schedule 1: Environmental Matters, page 4, paragraph 13 and Environmental Report, Appendix E: Stage 1 Archeological Assessment Report

Preamble:

An archeological assessment for the Project is required by the Ontario Heritage Act and Standards and Guidelines for Consultant Archaeologist (2011). Enbridge Gas stated that it would conduct the archeological assessments required by the for the Project during "…the Spring, Summer and Fall 2022". As part of the Environmental Report, Enbridge Gas included the Stage 1 Archeological Assessment Report for the Project. The Stage 1 Archaeological Assessment report recommends that a Stage 2 Archaeological Assessment be conducted for all potentially undisturbed sites within the Project's study area.

Question:

a) What is the status and projected completion of the surveys and studies required to conduct the Stage 2 Archeological Assessment?

b) What is the anticipated date for filing the Stage 2 Archaeological Assessment Report with the Ministry of Tourism, Culture and Sport (MTCS) for a review?

Response

a) The surveys and studies required to conduct the Stage 2 Archaeological Assessment for the Panhandle Loop are approximately 94% complete. The remaining 6% of surveys and studies required are specific to the Richardson Sideroad Station and adjacent lands. All surveys and studies are anticipated to be complete in the spring of 2024. /U

b) The Stage 2 Archaeological Assessment Report was filed with the Ministry of Citizenship and Multiculturalism ("MCM"), formerly the Ministry of Tourism, Culture and Sport ("MTCS") on January 25th, 2023, and is currently under review.[1] The report for the Richardson Sideroad Station and adjacent lands is anticipated to be filed with the MCM in the spring of 2024. /U

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a) [1] This Report excludes the surveys and studies specific to the Richardson Sideroad Station and adjacent lands. The Stage 2 Archeological Assessment Report for the Richardson Sideroad Station and adjacent lands is anticipated to be filed with the MCM in the spring of 2024.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit G, Tab 1, Schedule 1, pages 1-2

Preamble:

The proposed pipelines for the Project total approximately 31 km in length. The Project will require approximately 59.5 hectares (147 acres) of permanent easement. Enbridge Gas will also require approximately 83 hectares (205 acres) of temporary easement for construction and topsoil storage purposes.

Enbridge Gas has initiated meetings with the landowners where temporary or permanent land rights are required and will continue to meet with them to obtain all required land rights.

Question:

a) Please quantify the total required permanent and temporary easements for the Panhandle Loop and Leamington Interconnect separately.

b) Please identify the permanent and temporary easement agreements that have been obtained since the filing of this application.

c) Please provide an update on the status and prospect of remaining land negotiations where permanent and temporary easements are required. Please include any concerns raised by landowners and Enbridge Gas's responses.

d) Please discuss any expected delays with respect to obtaining the required land rights for the Project and its impact to the construction start and in-service date for the Panhandle Loop and Leamington Interconnect.

Response

a) Please see Table 1 below:

Table 1

Panhandle Loop	Acres	Hectares
TOTAL Proposed Permanent Easement	104	42.0
TOTAL Proposed Temporary Land Use (TLU)	177	71.6

b) – c) All required Easement and Temporary Workspace Agreements have been secured except for 2 properties.

One landowner (owning both properties) expressed a concern regarding the proposed location of an above-ground station, pipeline easement and temporary easement within the Project area. Enbridge Gas continues to evaluate all options and is taking the landowners comments into consideration.

d) Enbridge Gas expects to have acquired all necessary land rights in advance of commencing Project construction, and does not anticipate any delay to planned Project in-service date at this time.

ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit G, Tab 1, Schedule 1, pages 4-5, Table 1: Potential Permits/Authorizations for the Project

Preamble:

Enbridge Gas identified the potential permits and authorizations required for the Project and listed them in Table 1 at the reference above.

Enbridge Gas also stated that other authorizations, notifications, permits and/or approvals may be required in addition to those identified in Table 1.

Question:

a) For each of the potential permits/authorizations listed in Table 1, please confirm if it has been identified as a potential permit/authorization for the Panhandle Loop, Leamington Interconnect, or both.

b) For each of the potential permits/authorizations listed in Table 1, please confirm if it is required for the Project.

c) For each permit/authorization listed in Table 1 that Enbridge Gas requires, please provide an update on the status of the permit/authorization including when Enbridge Gas expects to acquire each required permit/authorization. Please also discuss any anticipated potential delays in acquiring each required permit/authorization.

d) Has Enbridge Gas identified to date any other required permits/authorizations, in addition to those listed Table 1? If so, please describe the required permit(s)/authorization(s), the status and expected date for acquisition of the permit(s)/authorization(s), and whether the permit(s)/authorization(s) are required for the Panhandle Loop, Leamington Interconnect, or both.

Response

a) to d) /U

Please see Table 1 below.

Enbridge Gas continues to make applications for all necessary permits and authorizations for the Project into the Fall of 2023 and anticipates having all permits and authorizations in place prior to the start of construction by March 31, 2024, with the exception of the Archeological Assessment and clearance from the Ministry of Citizenship and Multiculturalism ("MCM") for the Richardson Sideroad Station and adjacent lands, which is anticipated to be submitted in the spring of 2024 with clearance obtained by the summer of 2024. Please also see Exhibit I.STAFF.18.

Enbridge Gas continues to actively engage all required permitting agencies and has received positive feedback regarding the Project to date. Therefore, the Company does not anticipate any permitting delays.

Table 1: Potential Permits/Authorizations for the Project

AUTHORITY	PURPOSE	PERMIT STATUS
Provincial		
Ontario Energy Board	Pursuant to section 90(1) of the Act, an Order granting leave to construct the Project. Pursuant to section 97 of the Act, an Order approving the form of pipeline easement agreement found at Exhibit G, Tab 1, Schedule 1, Attachment 3, and the form of temporary land use agreement found at Exhibit G, Tab 1, Schedule 1, Attachment 4.	In Progress
Ministry of Transportation	Encroachment permit to cross Hwy 401.	In Progress
Ministry of Citizenship and Multiculturalism	Archaeological clearance under the *Ontario Heritage Act* (OHA).	In Progress
Plains Midstream Canada ULC	Encroachment Agreement to cross Plains Midstream pipelines.	Recieved
Ministry of Environment, Conservation and Parks	Permitting or registration under the *Endangered Species Act* (ESA) (2007).	Received for the Endangered Species Act (ESA) (2007)

	Permit to Take Water (PTTW) or Environmental Activity and Sector Registry (EASR) (surface and groundwater) under the *Ontario Water Resources Act* (1990).	In Progress for Permit to Take Water (PTTW)
Ministry of Energy	Provision of a letter confirming the procedural aspects of consultation with potentially impacted Indigenous communities undertaken by Enbridge Gas for the Project is satisfactory.	In Progress
Municipal		
County of Essex	Municipal Consent of proposed alignment, including road occupancy permits for crossings and access off municipal roads.	In Progress, received permits for early access
Municipality of Chatham-Kent		In Progress, received permits for early access
Municipality of Lakeshore		In Progress
Lambton County		In Progress
Other		
Canadian Pacific Railway	Crossing Agreement to cross under railway corridor.	In Progress
Via Rail Canada Inc.	Crossing Agreement to cross under railway corridor.	In Progress
Landowner agreements for easements, temporary working space and/or storage sites	Obtain required Easement agreements. Obtain required TLU Agreements.	In Progress
Lower Thames Valley Conservation Authority	Development Permits under Ontario Regulation 152/06 (Regulation of Development, Interference with Wetlands and Alterations to Shorelines and Watercourses), as per the *Conservation Authorities Act* (1990)	Received

ENBRIDGE GAS INC.

Answer to Interrogatory from
Three Fires Group ("TFG")

INTERROGATORY

References:

- Exhibit C, Tab 1, Schedule 1, p. 5
- Exhibit F, Tab 1, Schedule 1, Attachment 1, "Environmental Report, Panhandle Regional Expansion Project" (the "Environmental Report")

Preamble:

EGI has assessed the following facility alternatives:

(i) Upsizing of the existing NPS 16 Panhandle Line or NPS 20 Panhandle Line west of Dover Transmission;
(ii) Looping the existing NPS 20 Panhandle Line West of Dover Transmission and installing a Leamington lateral interconnect (ie. the Project); and
(iii) A new liquified natural gas (LNG) Plant.

EGI identified and assessed the following Integrated Resource Planning Alternatives ("IRPA"):

(i) Firm exchange between Dawn and Gateway;
(ii) Firm exchange between Dawn and Ojibway, in combination with looping the NPS 20 Panhandle line west of Dover Transmission and installing a Leamington lateral interconnect;
(iii) Trucked CNG deliveries to the Panhandle system; and
(iv) Enhanced Targeted Energy Efficiency (ETEE).

Question:

a) Please explain why only two facility alternatives, an upsize of existing pipelines and the construction of a new LNG plant, were considered and assessed, as opposed to other non-natural gas-based options?
b) Please indicate whether EGI has considered hybrid solutions for the Project and the expansion of the Panhandle System. If yes, please provide details and indicate why these solutions were considered with respect to financial impacts on ratepayers, and why/how they were ruled out of inclusion for further consideration. If not, please explain.

c) Has Enbridge sought any opportunities to work with IESO or any other electricity distributors to facilitate electricity-based energy solutions as part of the IRPA for the benefit of both electricity and gas ratepayers, and if not, why was this not done?
d) Has Enbridge assessed the need for the project in relation to any rapid expansion of electricity infrastructure in the region, and overall impacts on both electricity and gas ratepayers?
e) Would Enbridge expect any rapid expansion of electricity infrastructure in the region to impact the need for the proposed project?
f) How does Enbridge determine whether the alternatives it has chosen to assess represent a complete picture of the viable alternatives to the Project? What criteria are used by EGI when selecting and assessing potential project alternatives and IRP's?
g) Please explain how Enbridge assessed alternatives to the project with respect to short-term and generational financial impacts on ratepayers
h) Please explain how Enbridge assessed alternatives to the project, specifically as they relate to impacts on each of the Three Fires First Nations.
i) Please explain what project alternatives, including financial impacts on ratepayers, including First Nation ratepayers, were presented to each of the Three Fires First Nations.

Response

a) Through Enbridge Gas's assessment of facility alternatives, no additional alternatives were identified to meet customer demand. Please see Exhibit C, Tab 1, Schedule 1 for Enbridge Gas's assessment of project alternatives. Please also see the response to Exhibit I.STAFF.7 for more information on all alternatives assessed, including various facility alternatives. /U

Enhanced Targeted Energy Efficiency were also assessed under IRPAs (see Exhibit C, Tab 1, Schedule 1, Pages 10-21) and deemed not to be viable (please also see the response to Exhibit I.STAFF.7 Attachment 2).

b) Yes, hybrid alternatives were considered, including the IRPA described at Exhibit C, Tab 1, Schedule 1, Pages 16-19. For more information on the assessment of alternatives, please see the response to Exhibit I.STAFF.7. /U

c) No, Enbridge Gas did not identify viable electricity-based alternatives for the Project. However, Enbridge Gas did assess Enhanced Targeted Energy Efficiency ("ETEE") programming, but this alternative was deemed to be non-viable. For more information on the assessment of alternatives, please see the response at Exhibit I.STAFF.7.

The need for the proposed Project is underpinned by customer demands for natural gas specifically (as per the EOI process), which is used by natural gas-powered electricity generators as a supply input, to power their facilities, and by agricultural customers for heating and carbon dioxide (to feed plants). Electricity is typically used by agricultural customers for lighting and ventilation only.

d) No.

Customers in the Panhandle Area of Benefit were invited to share their new/incremental gas needs through the EOI process. They were also invited to share any plans to turnback or reduce current contract demands. The EOI was used to generate an informed forecast for net new expected demands in the Panhandle Market.

e) No.

As per the IESO reports (2021 APO & 2022 AAR), the rapid expansion of electricity infrastructure in the region is in response to growing demands and does not make reference to existing customers in the region converting their existing energy needs currently met by natural gas to electricity.

f) Enbridge Gas conducts an assessment to identify potential alternatives, including facility and non-facility alternatives, to provide a complete picture of options to meet customer demand. For the criteria used to assess alternatives, please refer to Exhibit C, Tab 1, Schedule 1, Pages 3-4.

g) Enbridge Gas assessed alternatives for economic feasibility (Exhibit C, Tab 1, Schedule 1, Page 3). This included an assessment of Net Present Value and cost per unit of capacity created, to assess long-term impacts. For more information on the assessment of alternatives, please see the response to Exhibit I.STAFF.7. /U

h) Enbridge Gas assessed alternatives for environmental and socio-economic impact (Exhibit C, Tab 1, Schedule 1, Page 4), recognizing that the chosen alternative should minimize impacts to Indigenous peoples, municipalities, landowners, and the environment relative to other viable alternatives. For more information on the assessment of alternatives, please see the response to Exhibit I.STAFF.7.

i) Please see the response to Exhibit I.TFG.1 part a).

ENBRIDGE GAS INC.

Answer to Interrogatory from
Three Fires Group ("TFG")

INTERROGATORY

References:

Environmental Report, Integrated Resource Planning (IRP), PDF p. 310

Preamble:

IRP is a framework through which Enbridge Gas reviews alternative approaches to meeting energy needs, before building new infrastructure such as:
(i) Delivering more energy without adding new pipelines using liquefied or compressed natural gas;
(ii) Lowering energy use through effective energy efficiency programs; and
(iii) Displacing conventional natural gas with carbon-neutral renewable natural gas and hydrogen.

Question:

a) Has EGI considered whether the existing system could deliver more energy without adding new pipelines? If so, please explain and include reasons for why this alternative is not feasible.
b) Has EGI considered whether energy efficiency programs could meet regional energy needs and possibly provide better financial cases for ratepayers? Please explain.
c) Will alternative fuels like renewable natural gas and hydrogen blends be transported in the existing loop and new pipeline? If so, how has EGI considered the impacts on ratepayers for those alternative fuels?
d) If alternative fuels will be transported, please comment on the measures taken to ensure pipeline integrity, and related integrity management costs to ratepayers. Please include short- and long-term measures.

Response

a) Yes, alternatives that deliver more energy without incremental pipeline facilities were considered. The alternative assessment evaluation included Liquefied Natural Gas, Compressed Natural Gas and incremental third-party supplies. These alternatives were determined to be non-viable mitigation for the forecast Panhandle System capacity shortfall (please see the response to Exhibit I.STAFF.7 Attachment 2).

b) Yes, as noted at Exhibit C, Tab 1, Schedule 1, Pages 20-21, Enbridge Gas assessed whether energy efficiency programs could meet the regional energy needs compared to the capacity created by the proposed Project. The assessment found that the Enhanced Targeted Energy Efficiency ("ETEE") alternative is not technically or economically feasible to meet forecasted demands. /U

c) and d)
Enbridge Gas believes that the natural gas system could be leveraged to reduce GHG emissions in Ontario by transitioning the system over time to deliver renewable natural gas ("RNG") and hydrogen. Contract customers who are direct purchase may purchase RNG as part of their supply. As proposed in Phase 2 of Enbridge Gas's Rebasing Application (EB-2022-0200) at Exhibit 4, Tab 2, Schedule 7, the Company has proposed a new Low Carbon Voluntary Program to enable system supplied customers the ability to voluntarily elect that a portion of their supply be RNG, pending OEB approval, beginning in 2025. However, Enbridge Gas has no immediate plans to blend RNG or hydrogen into the Panhandle System. /U

RNG is composed of mostly methane, as is natural gas, and is currently injected by various producers into some of Enbridge Gas's systems. This RNG is blended within the natural gas stream. RNG is a one for one replacement of natural gas by volume and therefore would not have an impact on the proposed Project. Pipeline integrity measures for RNG are similar to those for traditional natural gas.

Enbridge Gas intends to evaluate the compatibility of its pipeline facilities with hydrogen gas in the future.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Three Fires Group ("TFG")

INTERROGATORY

References:

- Environmental Report
- Ontario Energy Board: Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario (the "Environmental Guidelines"), Section 4.3.13 Social Impacts

Preamble:

The Environmental Guidelines provides that Social Impact Assessment ("SIA") is an integral component of environmental analysis and ensures that the extent and distribution of the Project's social impacts are considered in an explicit and systematic way.

The Environmental Guidelines further note that pipeline construction is associated with both real and perceived health and safety risks which may affect people's lives and how they feel about their homes and communities.

Question:

a) Please discuss whether EGI has considered the social impacts of the proposed project on the Three Fires First Nations. If yes, please provide details and all related reports, presentations, or other documents specific to the Three Fires First Nations. If no, please explain why not.
b) Please discuss whether EGI has considered the cultural heritage impacts of the proposed project on the Three Fires First Nations. If yes, please provide details and all related reports, presentations or other documents specific to each of the Three Fires First Nations. If no, please explain why not.
c) Please discuss whether the required SIA considered the Project's impacts on systemic social inequalities, including gender, gender diverse people, race, ethnicity, religion, age, mental or physical disability. If not, please explain why these identified types of social impacts were not considered as part of the SIA.
d) Please discuss whether EGI has considered the safety risks of the expected construction workforce on the surrounding communities and vulnerable individuals, including the Three Fires First Nations, including as it relates to

safety risks such as potential substance abuse, disproportionate impacts on women in communities, and impacts on the sex trade. If yes, please explain how EGI intends to mitigate the identified safety risks. If no, please explain why not and discuss how EGI intends to mitigate these types of safety risks of the Project in the surrounding communities.

Response

a) Yes, Enbridge Gas considered social impacts to the Three Fires First Nations. Potential impacts to Indigenous communities, including the Three Fires First Nations, are outlined in Section 5.3.3 of the ER.

b) Yes, Enbridge Gas considered the cultural heritage impacts of the Project. A Cultural Heritage Report was completed for the Project and was provided as part of the ER in Appendix F. The report concluded that there are no anticipated impacts to cultural heritage resources. /U

c) Potential impacts on socio-economic features are outlined in Section 5.3.3 of the ER and align with the OEB's Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario (2016).

   There would be no anticipated residual effects on systemic social inequalities due to the Project scope, anticipated existing local tradesperson workforce, and short duration of active construction timeline of approximately six months, coupled with the requirements of Enbridge Gas's Supplier Code of Conduct.

   Enbridge Gas's suppliers, which includes its contractors and subcontractors, are required to follow Enbridge Inc.'s policies including the Supplier Code of Conduct, which states:

   > Enbridge believes that each individual with whom we come in contact deserves to be treated fairly, honestly, and with dignity. We do not condone any form of harassment, discrimination, or inappropriate actions or language of any kind.

   Drug and Alcohol Programs, Respectful Workplace Training and Indigenous Peoples Awareness Training are specific to the Construction Contractor(s) that will construct the projects, which haven't been selected yet.

d) The Panhandle Environmental Report was prepared with consideration of the Ontario Energy Board's (OEB) *Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and facilities in Ontario, 7th*

Edition (2016) ("Guidelines"). Guidance on the consideration of Social Impacts is provided in Section 4.3.13 of the OEB Environmental Guidelines. The Guidelines discuss "both real and perceived health and safety risks" at pages 41 and 42, which in the Panhandle Environmental Report are addressed through mitigation recommendations such as safety fencing and a Traffic Management Plan.

In addition, to mitigate additional safety risks (e.g., harassment, substance abuse) within the community, Enbridge Gas's general contractors are required to follow Enbridge policies including the Supplier Code of Conduct, as described in part c) above.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Three Fires Group ("TFG")

INTERROGATORY

References:

Enbridge Inc. "Net Zero by 2050: Pathways to reducing our emissions"[3] (The "Net Zero Plan"), pp. 2 and 9-11

Preamble:

EGI notes that it "is aware of, has reviewed, and is working in conjunction with the municipalities within the Panhandle Market to determine whether the expansion of the Panhandle System impacts their ability to achieve the greenhouse gas emissions (GHG) reduction goals."

In March 2022, EGI published the Net Zero Plan which includes targets of reducing the intensity of GHG emissions from their operations by 35% by 2030 and achieving net zero greenhouse gas ("GHG") emissions from their business by 2050 (the "Commitments").

Question:

a) Please indicate and provide details of how Enbridge Inc. and EGI intend to reach the Commitments as it relates to the Project. Please comment on, and file any and all analysis EGI has performed in connection with, how the shipping and burning of methane gas across the traditional territories of the Three Fires First Nations will, or is anticipated to, affect the Commitments.
b) Has EGI modelled the fugitive methane emissions that will be released by the proposed Project? If yes, please describe the modelling that was undertaken and provide all related results. If not, please explain.
c) Please provide information on EGI's leak detection, repair and reporting protocol for related infrastructure, including accounting for fugitive emissions.
d) Canada has committed to developing a plan to reducing oil and gas methane emissions by at least 75 percent below 2012 levels by 2030, pursuant to the

[3] Enbridge Inc. "Net Zero by 2050: Pathways to reducing our emission" (March 2022), available online at: https://www.enbridge.com/~/media/Enb/Documents/About%20Us/Net_Zero_by_2050.pdf?la=en.

Global Methane Pledge (see Appendix B).[4] Please explain EGI's understanding of and describe how the Project contributes to or detracts from Canada's commitments under the Global Methane Pledge.

e) Please file any and all analysis EGI has performed to assess GHG emissions over the lifespan of the Project. If EGI has not undertaken any such analysis, please explain why no such analysis has been undertaken, in light of the Commitments.

<u>Response</u>

a) Enbridge Gas's assessment of the Project included calculating its incremental GHG emissions and demonstrating a plan to mitigate these emissions to support its commitment of achieving its 2030 emissions intensity reduction target and its 2050 net zero target. /U

The incremental GHG emissions associated with the proposed Project are 4,100 tCO_2e annual emissions, primarily from incremental compressor fuel use. The incremental emissions due to this Project represent less than 1% of current emissions.

The Project's scope 1 mitigation costs are currently based on the cost of purchasing carbon offsets. However, an assessment will be completed to determine the most appropriate emission reduction option.

b) Yes, Enbridge Gas has estimated the fugitive emissions for the project. Calculations were undertaken following the methodologies prescribed by provincial and federal GHG reporting programs, including the use of emission factors and engineering estimates, as well as company-specific emission factors based on direct measurement of fugitive emissions.

Considering the fugitive emissions due to operation only, the Project is estimated to result in an increase in fugitive emissions of approximately 120 tCO_2e/year

c) Enbridge Gas currently manages its fugitive emissions, in accordance with industry accepted best management practices (CSA Z620.1) and government regulations including the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)*, to reduce

[4] Government of Canada, News Release, "Canada confirms its support for the Global Methane Pledge and announces ambitious domestic actions to slash methane emissions" (October 11, 2021), available online at: https://www.canada.ca/en/environment-climate-change/news/2021/10/canada-confirms-its-support-for-the-global-methane-pledge-and-announces-ambitious-domestic-actions-to-slash-methaneemissions.html

emissions from its operations. In July 2020, Enbridge Gas implemented a harmonized leak operating standard, which includes:

(i) increased traceability and tracking of leak repairs,
(ii) increased monitoring frequencies,
(iii) harmonized repair timelines for above ground leaks, and
(iv) initiation of a station leak survey program.

Pipelines are inspected annually by way of a foot patrol, during which a leak survey is conducted. A flame ionization gas detector is utilized during the foot patrol in order to detect leaks, if present. The results of these surveys are tracked and applied to the appropriate fugitive emission calculations within Enbridge Gas's federal and provincial emissions regulatory reporting.

d) The Global Methane Pledge aims to reduce methane emissions by 30 percent below 2020 levels by 2030. Canada has committed to developing a plan to reduce methane emissions from oil and gas by at least 75 percent below 2012 levels by 2030. In November 2022, Environment and Climate Change Canada released their proposed regulatory framework to amend the existing federal Methane Regulations to achieve at least a 75% reduction in oil and gas sector methane by 2030 relative to 2012. /U

As indicated in part a) above, the proposed project would result in an increase in emissions of up to 4,100 tCO_2e/year over current emissions levels (methane accounting for approximately 290 tCO_2e/year). In support of Canada's commitments, Enbridge Gas will continue to comply with the Federal Methane Regulation, which was implemented in order to support Canada's methane reduction targets.

e) As discussed in response at a), Enbridge Gas has assessed emissions associated with the Project (operational only) and has determined that construction of the Project will result in an overall increase of up to 4,100 tCO2e/year compared to baseline emissions (please see Table 1 for further breakdown of this increase). /U

Table 1

Emissions Source	**Emissions (tCO_2e)**
Stationary Combustion	3,900
Fugitives	120
Vented	80
TOTAL	4,100

ENBRIDGE GAS INC.

Undertaking Response to OGVG

To reproduce Exhibit E, Tab 1, Schedule 4 just showing the distribution margin, on a best-efforts basis.

Response:

Please see Attachment 1.

Calculation of Revenue (Distribution Margins)

PREP - Panhandle Regional Expansion Project
InService Date: Nov-01-2024

Line	Project Year ($000's)		1	2	3	4	5	6	7	8	9	10
	Distribution costs are recovered from Contract rate classes based on Firm Contract Demand (CD)											
	The deemed incremental revenue is based on the capacity created by the Project											
	Contract Methodology: Total CD * 12 * Distribution Margin											
1	Distribution Margin $/M3 / month	0.097333										
2	Contract Demand 10^3m^3/month		1,623	2,762	3,087	3,412	3,737	4,003	4,003	4,003	4,003	4,003
3	Distribution Margin		$1,895	$3,227	$3,606	$3,985	$4,364	$4,676	$4,676	$4,676	$4,676	$4,676
	General Service Distribution Margin = Volumes * Distribution Margin											
4	Distribution Margin $ / M3 consumed	0.118892										
5	Volume 10 ^3 M^3		2,218	6,610	10,912	15,092	19,120	23,000	24,906	24,906	24,906	24,906
6	Distribution Margin		$264	$786	$1,297	$1,794	$2,273	$2,735	$2,961	$2,961	$2,961	$2,961
7	Total Distribution Margin		$2,159	$4,012	$4,903	$5,779	$6,638	$7,410	$7,637	$7,637	$7,637	$7,637

The Distributions margins are Jan 2023 rates

ENBRIDGE GAS INC.

Undertaking Response to OGVG

To provide a high-level estimate of the cost of distribution-related infrastructure Enbridge believes will be necessary in order to connect customers, connected to the transmission project, on a best-efforts basis.

Response:

Incremental distribution-related infrastructure costs are outside of the scope of the Project and are not known at this time. Subject to the timing and location of where future customers are connecting to the natural gas distribution network, Enbridge Gas estimates (at a high-level and on a best-efforts basis) potentially $48 million of additional future distribution infrastructure costs related to the incremental capacity provided by the proposed Project. /U

ENBRIDGE GAS INC.

Undertaking Response to ED

To provide another version of JT1.4 showing tax impacts, including with the tax netted out

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Response:

Please see Attachment 1 to this response.

Calculation of Revenue (Distribution Margins)

PREP - Panhandle Regional Expansion Project
InService Date: Nov-01-2024

Line	Project Year ($000's)		1	2	3	4	5	6	7	8	9	10
	Distribution costs are recovered from Contract rate classes based on Firm Contract Demand (CD)											
	The deemed incremental revenue is based on the capacity created by the Project											
	Contract Methodology: Total CD * 12 * Distribution Margin											
1	Distribution Margin $/M3 / month	0.097333										
2	Contract Demand 10^3m^3/month		1,623	2,762	3,087	3,412	3,737	4,003	4,003	4,003	4,003	4,003
3	Distribution Margin		$1,895	$3,227	$3,606	$3,985	$4,364	$4,676	$4,676	$4,676	$4,676	$4,676
	General Service Distribution Margin = Volumes * Distribution Margin											
4	Distribution Margin $ / M3 consumed	0.118892										
5	Volume 10 ^3 M^3		2,218	6,610	10,912	15,092	19,120	23,000	24,906	24,906	24,906	24,906
6	Distribution Margin		$264	$786	$1,297	$1,794	$2,273	$2,735	$2,961	$2,961	$2,961	$2,961
7	Total Distribution Margin		$2,159	$4,012	$4,903	$5,779	$6,638	$7,410	$7,637	$7,637	$7,637	$7,637
8	Income Tax (rate = 26.5%)		$572	$1,063	$1,299	$1,532	$1,759	$1,964	$2,024	$2,024	$2,024	$2,024
9	After Tax Total Distribution Margin		$1,587	$2,949	$3,604	$4,248	$4,879	$5,447	$5,613	$5,613	$5,613	$5,613

ENBRIDGE GAS INC.

Undertaking Response to ED

Re ER IR 1, page 2 table, to provide the table showing annual demand instead of cubic metres per day; if not, to explain why not.

Response:

Please refer to Table 1 below for the forecast annual demand for the Panhandle System, prepared on a best-efforts basis. The annual demand forecast is not produced at the required level of detail to identify Panhandle System volumes specifically and therefore the following assumptions were made:

General Service Market:

- Forecasted volumes are weather normalized volumes at the OEB-approved 2022 weather normal.
- The forecast portion identified as Panhandle System-related is based on the 15 year trend for the portion of total Union South rate zone volumes from the Windsor & Chatham district areas.

Contract Market:

- Contract firm volumes are based on the aggregate of contracts that are identified as being serviced utilizing the Panhandle system.

Table 1 - Panhandle System Annual Demand Forecast

/U

	Historical Actuals (10^3m^3)				Forecast (10^3m^3)										
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
General Service Firm (Total System Demand)	753,845	731,168	722,988	745,583	743,906	753,714	747,668	745,176	743,525	745,406	739,717	737,366	735,470	737,603	732,428
Contract Firm (Total System Demand)	770,910	811,445	882,882	1,013,088	977,963	1,039,895	1,310,552	1,348,293	1,384,033	1,419,774	1,455,515	1,491,256	1,526,997	1,562,737	1,598,478
Total System Demand Forecast	1,524,754	1,542,613	1,605,870	1,758,670	1,721,868	1,793,609	2,058,220	2,093,469	2,127,559	2,165,180	2,195,232	2,228,621	2,262,467	2,300,340	2,330,906
General Service Firm (Total Incremental Demand)	-	(22,677)	(8,180)	22,594	(1,677)	9,809	(6,046)	(2,492)	(1,651)	1,881	(5,689)	(2,352)	(1,895)	2,133	(5,175)
Contract Firm (Total Incremental Demand)	-	40,535	71,437	130,206	(35,125)	61,932	270,657	37,741	35,741	35,741	35,741	35,741	35,741	35,741	35,741
Total Incremental Demand Forecast	-	17,858	63,258	152,800	(36,802)	71,741	264,611	35,249	34,090	37,621	30,052	33,389	33,845	37,873	30,566
Total Incremental Demand Forecast (Cumulative)	-	-	-	-	(36,802)	34,939	299,550	334,799	368,888	406,510	436,562	469,951	503,797	541,670	572,236

ENBRIDGE GAS INC.

Undertaking Response to ED

To provide a table expressing attachments and average use per customer, to reconcile attachments with the forecast incremental demand for the stage 2 analysis

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Response:

The customer attachment forecast and average use per customer used in the stage 2 analysis can be found in Tables 1 and 2 below, respectively. /U

Table 1: Customer Attachment Forecast used in Stage 2 Analysis

	2024	2025	2026	2027	2028	2029
Residential Attachments	1,454	1,424	1,394	1,333	1,277	1,222
Small Commercial Attachments	114	109	107	102	99	94
Large Commercial Attachments	4	4	4	4	4	4
Small Industrial Attachments	0	1	0	1	0	1

Table 2: Normalized Average Consumption (NAC) used in Stage 2 Analysis

	m^3/year
Residential NAC	2,052
Small Commercial NAC	8,165
Large Commercial NAC	130,358
Small Industrial NAC	15,032

Table 3 below displays the difference in the customer attachment forecast used in the stage 2 analysis, compared to the customer attachment forecast provided in the response at Exhibit I.ED.2, Table 1. The difference is not material.

Table 3: Customer Attachment Variance – Stage 2 vs Exhibit I.ED.2, Table 1

	2024	2025	2026	2027	2028	2029
Residential Attachments	0	0	0	0	0	0
Commercial Attachments	3	1	2	1	2	0
Industrial Attachments	(3)	(1)	(2)	(1)	(2)	0

The average use per customer in the stage 2 analysis cannot be directly compared to the average use per customer in the response at Exhibit I.ED.2, as the former is presented in annual m^3 consumption while the latter is m^3/hr demand.

ENBRIDGE GAS INC.

Undertaking Response to ED

To provide the referenced figures as demand day rather than demand hour figures

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Response:

See below for the figures provided at Exhibit I.ED.2 p. 2, restated in m^3/day (rather than m^3/hr). /U

Residential: 0.89 m^3/h = 17.8 m^3/d
Commercial/Industrial: 9.72 m^3/h = 194.4 m^3/d

ENBRIDGE GAS INC.

Undertaking Response to ED

To make best efforts to restate the table at ED 3, page 2, using cubic metres per hour

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Response:

Table 1 below reflects Table 2 from Exhibit B, Tab 1, Schedule 1 restated in m3/h. Additionally, as requested in Exhibit JT1.23, Table 1 below also provides Greenhouses broken out on a best effort basis.

Table 1: Panhandle System Design Day Demand Forecast

	Historical Actuals (m3/h)			FORECAST (m3/h)									
	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
General Service Firm	406,888	392,665	394,201	391,613	394,043	396,435	398,744	400,989	403,139	405,207	407,174	409,045
Greenhouse - Firm Contract Only	254,499	285,050	323,048	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Power Generators - Firm Contract only	112,411	112,768	112,504	112,543	112,543	173,668	207,808	207,808	207,808	207,808	207,808	207,808
Large Commercial/Industrial - Firm Contract only	75,999	79,207	66,569	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total System Demand Forecast	849,798	869,690	896,323	943,478	989,066	1,072,984	1,129,832	1,152,478	1,175,028	1,197,496	1,219,862	1,242,134
General Service Firm	24,316	(11,115)	1,935	(4,604)	2,430	2,393	2,308	2,246	2,150	2,068	1,967	1,871
Greenhouse - Firm Contract Only	44,773	32,494	38,288	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Power Generators - Firm Contract only	(23,574)	1,216	(149)	(537)	-	61,125	34,141	-	-	-	-	-
Large Commercial/Industrial - Firm Contract only	(4,425)	3,788	(12,557)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Incremental Demand Forecast	41,090	26,383	27,517	42,573	45,588	83,918	56,848	22,646	22,550	22,468	22,366	22,272
Total Incremental Demand Forecast (Cumulative)	-	-	-	42,573	88,161	172,079	228,926	251,573	274,123	296,591	318,957	341,228

ENBRIDGE GAS INC.

Undertaking Response to ED

To restate the table at ED 3, page 2, showing greenhouses broken out from the contract firm

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Response:

Table 1 below reflects Table 2 from Exhibit B, Tab 1, Schedule 1 with Greenhouses broken out on a best effort basis.

Table 1: Panhandle System Design Day Demand Forecast

	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
General Service Firm	317	308	310	306	308	310	312	314	315	317	319	320
Greenhouse - Firm Contract Only	159	179	203	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Power Generators - Firm Contract only	105	106	106	106	106	163	195	195	195	195	195	195
Large Commercial/Industrial - Firm Contract only	59	62	52	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total System Demand Forecast	**640**	**656**	**672**	**698**	**730**	**802**	**849**	**863**	**878**	**892**	**906**	**921**
General Service Firm	19	-9	2	-4	2	2	2	2	2	2	2	1
Greenhouse - Firm Contract Only	28	20	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Power Generators - Firm Contract only	-22	1	0	-1	0	57	32	0	0	0	0	0
Large Commercial/Industrial - Firm Contract only	-3	3	-10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Incremental Demand Forecast	**21**	**16**	**16**	**26**	**32**	**72**	**47**	**15**	**14**	**14**	**14**	**14**
Total Incremental Demand Forecast (Cumulative)				**26**	**58**	**130**	**177**	**192**	**206**	**220**	**235**	**249**

ENBRIDGE GAS INC.

Undertaking Response to ED

To provide the source for the NRCAN pricing for heating oil and propane

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Response:

The sources used in the stage 2 analysis can be found at the following links: /U

Heating Oil:
2022 –
https://www2.nrcan.gc.ca/eneene/sources/pripri/prices_bycity_e.cfm?productID=7&locationID=19&frequency=W&priceYear=2022&Redisplay=

2023 –
https://www2.nrcan.gc.ca/eneene/sources/pripri/prices_bycity_e.cfm?productID=7&locationID=19&frequency=W&priceYear=2023&Redisplay=

Propane:
2022 –
https://www2.nrcan.gc.ca/eneene/sources/pripri/prices_bycity_e.cfm?productID=6&locationID=19&frequency=W&priceYear=2022&Redisplay=

2023 –
https://www2.nrcan.gc.ca/eneene/sources/pripri/prices_bycity_e.cfm?productID=6&locationID=19&frequency=W&priceYear=2023&Redisplay=

ENBRIDGE GAS INC.

Undertaking Response to ED

To advise (a) the penalty to be paid if the 58 TJ's per day is cancelled before acceptance of any incremental gas; (b) to advise the NPV of the incremental revenue included in the stage 1 DCF analysis associated with the flow from this incremental power generation demand. If the question cannot be answered, to advise and explain why.

Response(s):

a) No such penalty is contemplated within the customer's contract as Enbridge Gas has no reason to expect that the customer will not require the incremental firm services sought.

b) The 58 TJ/day referenced in the initial undertaking has been updated to 89 TJ/day, as per the request at Exhibit I.ED.24. The incremental revenue associated with the 89 TJ/day of power generation has an NPV impact of approximately $56 million. /U

ENBRIDGE GAS INC.

Undertaking Response to ED

To make best efforts to estimate the diversity in the reduction and overall demand due to diversity of these new customers, based on existing customers

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Response:

The total demand of contracts that have been executed and/or in negotiation set out in the response to Exhibit I.STAFF.24 a), is 131.2 TJ/d. Enbridge Gas is unable to forecast the exact diversity of forecast incremental demand until it is realized due to customer location, equipment type, and actual operation. Diversification for these customer types is not applied to forecast demands due to the potential range in variation. Once the customers are connected to the system, only then are the demands included in the diversification based on actual customer consumption. However, to be responsive and on a best-efforts basis, the Company has applied the updated historical diversification assumptions to the incremental contracts that have been executed and/or in negotiation. Based on these assumptions, the 131.2 TJ/d would be increased to 132 TJ/d which is an increase of approximately 0.8 TJ/d. However, the Company cautions against drawing conclusions based on this estimate, due to the potential variability noted above. /U

ENBRIDGE GAS INC.

Undertaking Response to OEB STAFF

Staff Follow-up Question #3

References:
Enbridge Gas Response to Interrogatory OEB Staff.15 (c) Enbridge Gas Response to Interrogatory ED.14 (a) Exhibit E, Tab 1, Schedule 1, p. 7

Preamble:
Enbridge Gas noted that the natural gas price of $0.14/m3 used in the Stage 2 DCF analysis is the 2021 average effective price determined using the posted effective price on the OEB's website.

Enbridge Gas noted that the Stage 2 NPV energy cost savings are estimated to be in the range of approximately $214 million over a period of 20 years to $335 million over 40 years.

Question:

Please advise whether the Stage 2 NPV energy cost savings would be in the range of approximately $182 million over a period of 20 years to $284 million over 40 years if the 2022 average effective price ($0.26/m3) was used in the analysis instead. If this is not correct, please provide the correct NPV energy cost savings using the 2022 average effective price for natural gas.

Response(s):

Enbridge Gas cannot confirm the updated Stage 2 NPV energy cost savings would be in the range of approximately $182 million over 20 years to $284 million over 40 years if the 2022 average effective price of natural gas of $0.26/m^3 was used. The Stage 2 NPV energy cost savings results would be in the range of $237 million over 20 years to $370 million over 40 years. However, this scenario does not align with the prices used for the alternative fuels. As noted in Exhibit E, Tab 1, Schedule 6, the alternative fuel prices are the average posted prices for the 12 month period ending March 2023. /U

ENBRIDGE GAS INC.

Undertaking Response to OEB STAFF

Staff Follow-up Question #2

References:
Enbridge Gas Response to Interrogatory OEB Staff.12
EB-2022-0088, Exhibit D, Tab 1, Schedule 1, p. 1

Preamble:
A comparison of the project costs for the Panhandle Loop and the Panhandle Reinforcement Project is set out in the below table.

Table 1

Item No .	Description	(a) Current Project Panhandle Loop	(b) Comparison Forecast (2017PRP) (EB-2016-0186)	(c) Comparison Actual 2017 PRP (EB-2016-0186)	(d) =(a) - (c) Variance to Actual
	Pipeline Diameter Length (km) Pipeline Material	*NPS 36 19km Steel*	*NPS 36 40km Steel*	*NPS 36 40km Steel*	
1	Materials	56,600,000	23,800,000	24,480,000	32,120,000
2	Labour	124,100,000	203,754,000	202,374,000	(78,274,000)
3	Contingency	19,200,000	34,133,000		19,200,000
4	Interest During Construction	3,500,000	2,781,000	1,837,000	1,663,000
5	Total Direct Capital Cost	203,400,000	264,468,000	228,691,000	(25,291,000)
6	Indirect Overheads	43,200,000	-		43,200,000
7	Total Project Cost	246,600,000	264,468,000	228,691,000	17,909,000
8	Total Cost per km	12,979,000	6,612,000	5,717,000	7,262,000
9	Material Cost per km	2,979,000	595,000	612,000	2,367,000
10	Labour, External permitting and land, and Outside Services per km	6,532,000	5,094,000	5,059,000	1,473,000

The proposed project costs for the Dawn to Corunna project are set out in the table below.

Table 2

Item #	Description	Pipeline Costs	Ancillary Costs	Total Costs
1.0	Materials	$11,800,354	$36,643,592	$48,443,946
2.0	Construction & Labour	$51,310,846	$28,993,020	$80,303,866
3.0	External Permitting & Lands	$15,322,222	$0	$15,322,222
4.0	Outside Services	$19,230,385	$15,702,325	$34,932,710
5.0	Direct Overheads	$1,295,000	$0	$1,295,000
6.0	Contingency	$13,180,351	$10,816,348	$23,996,699
7.0	IDC	$2,093,000	$0	2,093,000
8.0	**Project Cost**	**$114,232,158**	**$92,155,285**	**$206,387,443**
9.0	Indirect Overheads & Loadings	$26,277,051	$18,085,209	44,362,260
10.0	**Total Project Costs**	**$140,509,209**	**$110,240,494**	**$250,749,703**

NOTE:
The total costs set out in Table 1 include abandonment of the existing seven CCS compressor units K701-K703 and K705-K708 amounting to $14.5 million.

Questions:

a) Please separate the Panhandle Loop costs into pipeline costs and ancillary costs, as applicable, using the same itemized cost descriptions as in Table 1 to allow for a comparison of only the pipeline costs between the Panhandle Loop and the Dawn to Corunna project.

b) In response to this question:
   i. Please provide a table, using the same itemized cost description as in Table 1, separately comparing the pipeline costs between the Panhandle Loop and the Dawn to Corunna project. OEB staff is seeking to compare the material and labour costs per km of the Panhandle Loop and a recent proposed project.
   ii. Please include a discussion of any material differences between the two projects that would lead to significant cost differences with respect to the pipeline only costs, as applicable.

Response(s):

/U

a) & b)

Please see Table 1 at Exhibit E, Tab 1, Schedule 1. Please see the Table 1 below comparing the pipeline costs between the Panhandle Loop and the Dawn to Corunna project.

Table 1: Project Cost Comparison – Pipeline Costs ($ Millions)

Item No.	**Description**	**(a)** **Proposed Project** Panhandle Loop (EB-2022-0157)	**(b)** **Current Forecast** Dawn to Corunna (EB-2022-0086)	**(c) = (a) - (b) Variance to Actual**
	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:

- The proposed Project mainline estimate is inclusive of the Richardson Sideroad end point valve site.
- 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.
- Reduced contingency for the Dawn to Corunna Replacement Project due to its current stage of development/execution.

Table 1

ii. Variances in estimated costs per kilometer between the NPS 36 Panhandle Loop and the NPS 36 Dawn to Corunna pipeline are primarily related to labour and contingency costs and can be attributed to the complexity of the Panhandle loop and differences in the timing of estimate development and their respective class level at the time of filing:

- The Panhandle loop has a more complex mainline scope with eight (8) trenchless crossings compared to one (1) trenchless crossing for the Dawn to Corunna project.
- The Panhandle loop mainline estimate is inclusive of the Richardson sideroad end point valve site.
- The cost estimate for Dawn to Corunna was completed in Q2 2023 just before commencing construction and with executed contracts, requiring less contingency. The cost estimate for the Panhandle Loop was completed in Q2 2023, one year before the construction start date, using a contingency that accounts for uncertainty in contracts and market conditions.

ENBRIDGE GAS INC.

Undertaking Response to Middle Road Farms Limited (Courey Corporation)

To advise a calculated figure for pressure drop in the existing pipeline between Wheatley Road and Richardson Sideroad.

Response(s):

Please refer to Table 1 and Figure 1 below. /U

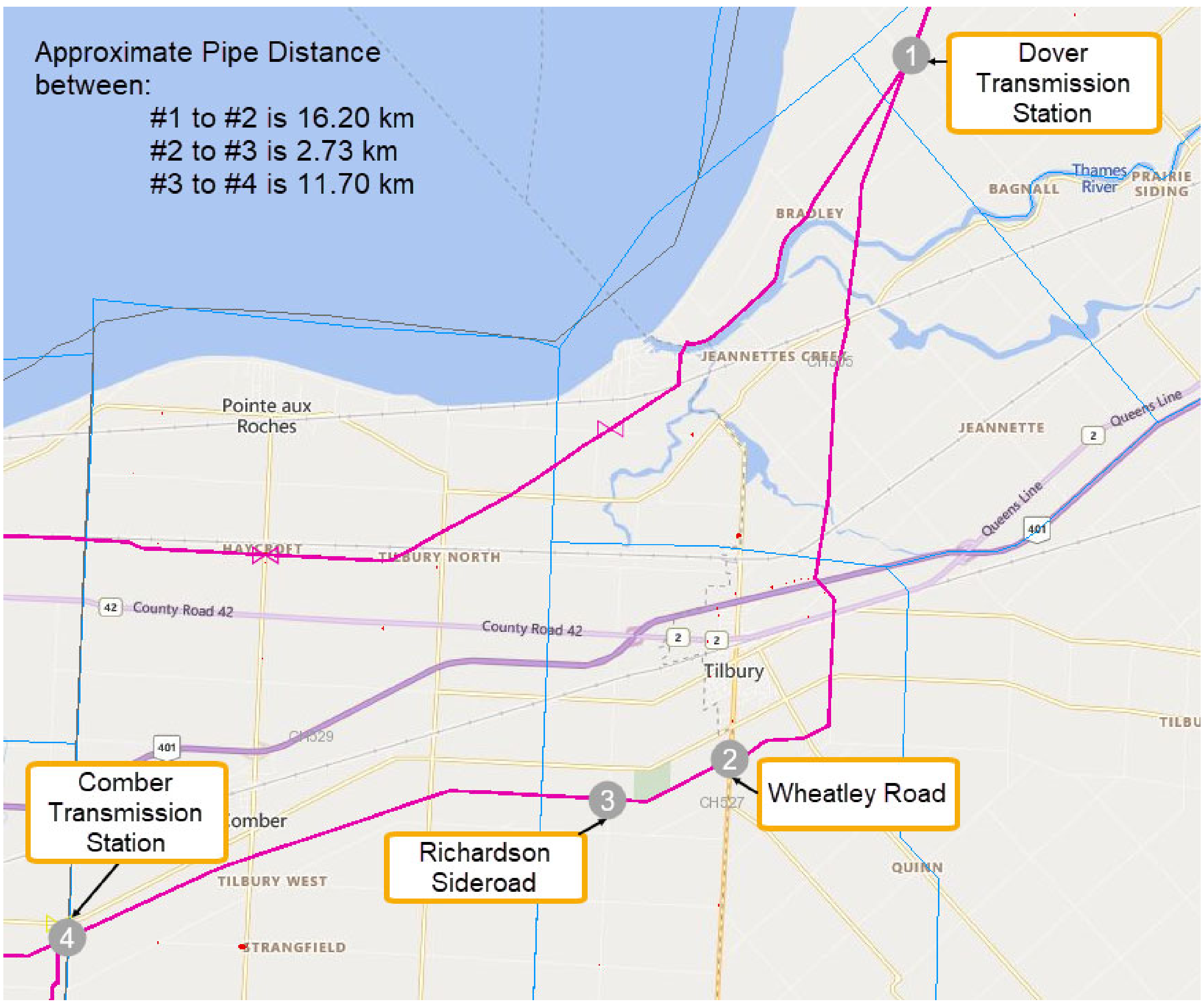
Since the year of interest was not specified in the request, results from two winters were provided: Winter 2021/2022 and 2024/2025 (which is the first year where incremental capacity is needed).

Please note that the Panhandle System's minimum inlet pressure at the Brighton Beach Power Generation station and at Leamington North Gate Station cannot be maintained under the Winter 2024/2025 scenario in Table 1. This information is shown in more detail at Exhibit B, Tab 2, Schedule 1, Attachment 1.

Table 1: Pressure Drop between Dover Transmission and Comber Transmission Stations without the Proposed Project

Winter Year	Pressure Drop from Location to Location (kPag)		
	Dover Transmission to Wheatley Road [#1 to #2]	*Wheatley Road to Richardson Sideroad [#2 to #3]*	*Richardson Sideroad to Comber Transmission [#3 to #4]*
Winter 2021/2022	728	134	627
Winter 2024/2025	1270	254	1342

Figure 1: Map of Station Locations Provided in Table 1



ENBRIDGE GAS INC.

Undertaking Response to Middle Road Farms Limited (Courey Corporation)

To produce data showing pressures at Wheatley Road now, and the pressure drop that would be experienced at Richardson Sideroad without this extension past Wheatley Road

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Response(s):

Table 1 below shows the minimum pressure at Dover Transmission, Wheatley Road, Richardson Sideroad and Comber Transmission along the existing NPS 20 Panhandle Line. /U

Table 2 below shows the pressure drop between the same key points between Dover Transmission and Comber Transmission. Please refer to Figure 1 in the response at Exhibit JT2.9 for a visual representation of the locations.

Tables 1 and 2 include the pressure and pressure drop from:
a) The current Winter 2021/2022 without the proposed Project.
b) The future Winter 2028/2029, with an NPS 36 Panhandle Loop terminated at Wheatley Road instead of Richardson Sideroad.

Shortening the NPS 36 Panhandle loop of the existing NPS 20 Panhandle Line to Wheatley Road does not provide enough capacity to serve the 5-year demand forecast through Winter 2028/2029. Ending the NPS 36 Panhandle loop at Wheatley Road decreases the proposed Project's capacity by 26 TJ/d.

Table 1: Minimum pressure at Wheatley Road and Richardson Sideroad along NPS 20 Panhandle Line

Project to Wheatley Road Only		**Pressure (kPag)**	
Winter Year		*Wheatley Road*	*Richardson Sideroad*
Current System	Winter 21/22	5135	5001
Year 5 of Project	Winter 28/29	5739	5443

Table 2: Pressure drop between Wheatley Road and Richardson Sideroad

Project to Wheatley Only		**Pressure Drop from Location to Location (kPag)**
Winter Year		*Wheatley Road to Richardson Sideroad [#2 to #3]*
Current System	Winter 21/22	134
Year 5 of Project	Winter 28/29	296

ENBRIDGE GAS INC.

Undertaking Response to Middle Road Farms Limited (Courey Corporation)

To provide a table showing pressures and flows for a typical summer day for the 2025-26 operating year, for a typical winter day for the same period, and the peak design day.

Response(s):

Table 1 provides the flow and minimum pressure results at the Dawn Compressor Station, Dover Transmission Station, Wheatley Road, Richardson Sideroad and Comber Transmission Station for a typical day in Summer 2026, typical winter day in 2025/2026, and Design Day for Winter 2025/2026 for each of the following scenarios: /U

- Existing System (without the Proposed Project)
- System with the Proposed Project

Please see Figure 1 in the response to Exhibit JT2.9 for a visual representation of the area.

It is important to note there are no stations, direct connected customers, or take-offs to any downstream distribution system between Dover Transmission Station and Comber Transmission Station. The NPS 20 Panhandle Line between Dover Transmission and Comber Transmission stations delivers natural gas to customers at and west of Comber Transmission Station in the Windsor and Leamington Kingsville markets.

Table 1: Flow and Minimum Pressure for the Existing System and with the Proposed Project for Winter 2025/2026 and Summer 2026

	Existing System		System with Proposed Project	
	Flow ($10^3m^3/d$)	Pressure (kPag)	Flow ($10^3m^3/d$)	Pressure (kPag)
Typical Summer Day (Summer 2026)				
Dawn Compressor Station	7703	4827	7703	4827
Dover Transmission Station (to NPS 20)	3813	4783	3813	4783
Wheatley Road	3813	4619	3813	4776
Richardson Side Road	3813	4591	3813	4774
Comber Transmission Station	3813	4468	3813	4655
Typical Winter Day (Winter 2025/2026)				
Dawn Compressor Station	15858	5971	15858	6040
Dover Transmission Station (to NPS 20)	10197	5833	10197	5897
Wheatley Road	10197	4888	10197	5865
Richardson Side Road	10197	4710	10197	5860
Comber Transmission Station	10197	3843	10197	5176
Design Day (Winter 2025/2026)				
Dawn Compressor Station	Pressures are too low; the model will not solve with only the existing infrastructure.		19428	6040
Dover Transmission Station (to NPS 20)			13088	5820
Wheatley Road			13088	5769
Richardson Side Road			13088	5760
Comber Transmission Station			13088	4559

ENBRIDGE GAS INC.

Undertaking Response to Middle Road Farms Limited (Courey Corporation)

To provide a table showing pressures and flows at the three locations of Dawn, Wheatley Road, and comber transmission for summer day, winter day, and peak design day.

Response(s):

Table 1 below summarizes the minimum system pressures and flows at Dawn Compressor Station, Dover Transmission Station, Wheatley Road, Richardson Sideroad and Comber Transmission Station for each typical summer day in 2026, a typical winter day in 2025/2026, and Design Day for winter 2025/2026. /U

“Existing Pipeline” refers to the current system without any reinforcement, and “New Pipeline” refers to the NPS 36 Loop from Dover Transmission to Wheatley Road instead of Richardson Sideroad (2.72 km shorter than the proposed Project).

It is important to note there are no stations, direct connected customers, or take-offs to any downstream distribution system between Dover Transmission Station and Comber Transmission Station. The NPS 20 Panhandle Line between Dover Transmission and Comber Transmission stations delivers natural gas to customers at and west of Comber Transmission Station in the Windsor and Leamington Kingsville markets.

As shown in the two scenarios below, looping from Dover Transmission to Wheatley Road reduces pressure drop between Dover Transmission to Wheatley Road. The un-looped sections of the NPS 20 Panhandle Line maintain higher pressure drop including the segments from Wheatley Road to Richardson Sideroad, and subsequently to Comber Transmission.

When results from Table 1 are compared to the results detailed within Exhibit JT2.11, Table 1 (ending the loop at Richardson Sideroad), terminating the loop at Richardson Sideroad reduces the pressure drop from 252 kPag to 9 kPag, bringing additional pressure to Comber Transmission to serve downstream markets.

Furthermore, as shown in Exhibit JT2.10 Table 3, looping from Dover Transmission to Richardson Sideroad compared to terminating at Wheatley Road, provides an incremental 26 TJ/d of system capacity and can serve the minimum 5-year shortfall of 156 TJ/d.

Table 1: Showing minimum pressures and flows of the existing pipeline system to the Proposed Project but ending the NPS 36 loop at Wheatley Road, with 2025/2026 forecast demands

Demands from 2025/2026	Existing Pipeline		New Pipeline *(Loop ending at Wheatley Road)*	
	Flow (km^3/d)	Pressure (kPag)	Flow (km^3/d)	Pressure (kPag)
Typical Summer Day (Summer 2026)				
Dawn Compressor Station	7703	4827	7703	4827
Dover Transmission to Leamington	3813	4783	3813	4783
Wheatley Road	3813	4619	3813	4776
Richardson Side Road	3813	4591	3813	4748
Comber Transmission Station	3813	4468	3813	4628
Typical Winter Day (Winter 2025/2026)				
Dawn Compressor Station	15858	5971	15858	6040
Dover Transmission to Leamington	10197	5833	10197	5897
Wheatley Road	10197	4888	10197	5866
Richardson Side Road	10197	4710	10197	5716
Comber Transmission Station	10197	3843	10197	5014
Design Day (Winter 2025/2026)				
Dawn Compressor Station	Pressures are too low; the model will not solve with only the existing infrastructure.		19428	6040
Dover Transmission to Leamington			13088	5822
Wheatley Road			13088	5772
Richardson Side Road			13088	5520
Comber Transmission Station			13088	4258