EB-2020-0091

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act*, 1998, S. O. 1998, c. 15, Schedule B;

AND IN THE MATTER OF a generic hearing on Integrated Resource Planning.

Green Energy Coalition Compendium

February 26, 2021

David Poch, Counsel

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ENBRIDGE GAS INC.

Undertaking Response to GEC

To provide AMP data 10 years out, if available, or shorter periods, as available.

Response:

Enbridge Gas has not historically produced a long-range forecast in any format that would meet the intent of the undertaking. Up to 2019, Enbridge Gas operated as two separate entities. For each of the legacy utilities, and for Enbridge Gas, a demand forecast is filed annually for the following year as noted in the response at Exhibit I.OSEA.10, and clarified in the response at Exhibit JT1.13.

A 10-year customer forecast is filed in the Asset Management Plan and has been filed as part of multiple rates cases, but that process only started in around 2018.

The Gas Supply Plan (and Annual Updates) was filed for 2019, 2020 and 2021, and it contains some of the information that parties are seeking.

ENBRIDGE GAS INC.

Undertaking Response to Anwaatin

To advise whether IRPA's are in scope within a rebasing proceeding.

Response:

To the extent that Enbridge Gas's future rebasing proceedings include a forecast of capital projects in the form of an updated Asset Management Plan, the Company expects that any identified system constraints and related IRPAs or facility alternatives discussed in the AMP to resolve those constraints over the next IRM-period would be within the scope of what may be considered relevant in that proceeding. The degree to which future capital spending plans are relevant would depend on the form of ratemaking model being considered.

Enbridge Gas does caution, however, that review of future IRPA plans in any rebasing review should be limited in scope, taking into account that Enbridge Gas has committed to conduct an annual Stakeholder Day to discuss and receive feedback on them and that the Company intends to apply separately for specific approval to invest in either facility or non-facility (IRPA) projects.

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ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

Exhibit B, Page 38

The company proposes monitoring and reporting on IRPA's that are implemented. What reporting will there be of screened out IRPAs? What will be the timing of any such reporting? What mechanism does the company foresee will allow interested parties to review and challenge such determinations in a timely fashion?

Response

Consistent with the response at Exhibit I.STAFF.6 and its Additional Evidence, Enbridge Gas will reflect preferred facility alternatives and/or IRPAs in its Asset Management Plan ("AMP") filed with the Board which will be subject to review by the Board and intervenors. Enbridge Gas will continue to monitor underlying system constraints until such time that an IRPA(s) or facility alternative is fully implemented. In the event the underlying constraint changes prior to implementation, Enbridge Gas may need to revise its plans and update the AMP. Enbridge Gas intends to file an IRP Report on the performance of OEB-approved IRPAs annually with the Board.

Enbridge Gas does not intend to report on any IRPAs that have been screened out as part of Enbridge Gas's proposed IRPA screening process as doing so would require excessive administration and management at considerable incremental cost to ratepayers for limited incremental value in return. Such indefinite and infinite re-assessment of IRPA(s) would not be efficient and may encourage inappropriate re-assessment of investment decisions in hindsight. Instead, consistent with Enbridge Gas's proposal for Monitoring and Reporting and the response at Exhibit I.STAFF.10, Enbridge Gas will report annually on the performance of OEB-approved IRPA(s) and in instances of underperformance may make adjustments to resolve unanticipated operational challenges or flaws in the design or delivery of IRPAs. Wherever such adjustments could lead to increased costs greater than 25% of total OEB-approved costs for individual IRPA investments Enbridge Gas would apply to the OEB for approval to make the adjustments, at which time the Board and intervenors would have the opportunity to review and ensure that the adjustments proposed by the Company are optimal and prudent.

ENBRIDGE GAS INC.

Undertaking Response to ED

To advise the best time to screen out IRPA's before a leave-to-construct application.

Response:

If (contrary to Enbridge Gas's proposal) the Board was to determine that an adjudication of Enbridge Gas's decision not to pursue an IRP solution to meet an identified need/constraint should take place before the LTC application where the facilities solution is presented, then Enbridge Gas believes that such adjudication should take place in the year after Enbridge Gas has presented its determination not to pursue an IRPA. That would provide early clarity to Enbridge Gas as to how to proceed to meet the identified need/constraint.

Table 6.1-3 and **Table 6.1-4** list the ICM-eligible capital projects for the EGD and Union rate zones respectively. Investment costs do not include overheads.

Table 6.1-3: ICM-Eligible Capital Projects – EGD Rate Zone

Asset Class	Project Name	In-Service Year	2021-2025 Net Capital ($M)	Total Net Capital ($M)	Driver
Distribution Growth	Rideau Reinforcement	2025	52.7	53.5	Mandatory: Reinforcement Specified per Network Analysis
	York Region Reinforcement	2026	25.9	65.8	Mandatory: Reinforcement Specified per Network Analysis
	Amaranth System Reinforcement	2024	10.3	10.3	Mandatory: Reinforcement Specified per Network Analysis
	Thornton Reinforcement	2023	10.9	10.9	Mandatory: Reinforcement Specified per Network Analysis
Distribution Pipe	NPS 20 Lake Shore Replacement (Cherry to Bathurst)	2022	103.4	104.7	Condition
	St. Laurent Phase 3[13] St. Laurent Plastic - Montreal to Rockcliffe St. Laurent Plastic - Coventry/Cummings/St Laurent St. Laurent Plastic - Lower Section	2021	12.4	12.4	Condition
	NPS 12 St. Laurent Aviation Pkwy[13]	2022	29.5	29.8	Condition
	NPS 12 St. Laurent Queen Mary/Prince Albert[13]	2022	11.0	11.1	Condition
	NPS 12 Martin Grove Rd Main Replacement: Lavington to St. Albans Road	2024	18.3	18.3	Condition
	NPS 10 Glenridge Avenue, St. Catharines	2025	11.8	11.8	Condition
Distribution Stations	Harmer District Station	2022	13.1	13.1	Compliance and ILI requirements
Compression Stations	SCOR: K701/2/3 Reliability - Replacement	2024	185.2	185.2	Obsolescence
	Dehydration Expansion	2023	41.0	41.0	Condition; Growth

[13] *The St. Laurent portfolio of work consists of four phases of work and each phase is comprised of separate projects. Phases 1 & 2 have been previously completed, with Phases 3 & 4 remaining in this forecast period. Phase 3 includes the following investments: Three PE main investments in 2021 including Lower Section, Coventry/Cummings/St Laurent and Montreal to Rockcliffe. Phase 4 includes the following investments: NPS 12 St. Laurent Aviation Pkwy and NPS 12 St. Laurent Queen Mary/Prince Albert in 2022. The investments comprising Phases 3 & 4 will be combined in a single Leave to Construct application that will be submitted in Fall 2020.*

Asset Class	Project Name	In-Service Year	2021-2025 Net Capital ($M)	Total Net Capital ($M)	Driver
	SCOR: Meter Area-Upgrade	Ph 1 - 2021 Ph 2 - 2022	34.2	45.5	Condition
	Storage Crowland (SCRW): Station-Renewal In-Place	2025	27.9	27.9	Obsolescence
Transmission Pipe and Storage	Crowland Pool (PCRW): Wells-Upgrade	2026	1.7	11.7	Compliance, Condition
REWS	Kennedy Road Expansion	2023	15.0	26.3	Condition
	Station B New Building	2021	15.5	17.6	Condition, Function, In Progress
	SMOC/Coventry Facility Consolidation	2023	30.8	30.8	Function and Service Coverage Duplication
	Kelfield Operations Centre	2023	10.8	10.8	Condition, Function
	VPC Core and Shell	2025	20.0	20.0	Condition

Note: Dismantlement costs are not included in Total In-Service Capital.

Table 6.1-4: ICM-Eligible Capital Projects – Union Rate Zones

Asset Class	Project Name	In-Service Year	2021-2025 Net Capital ($M)	Total Net Capital ($M)	Driver
Distribution Growth	Customer Stratford Reinforcement	2022	13.3	13.3	Mandatory: Reinforcement Specified per Network Analysis
	Dunnville Line Reinforcement (6.3 km of NPS 10)	2022	9.1	9.1	Mandatory: Reinforcement Specified per Network Analysis
	NBAY: Parry Sound Lateral Reinforcement (12.5 km of NPS 6)	2023	15.0	15.0	Mandatory: Reinforcement Specified per Network Analysis
	WATE: Owen Sound Transmission System, Reinforcement (28.8 km of NPS 16)	2025	81.7	83.6	Mandatory: Reinforcement Specified per Network Analysis
	LOND: Goderich Transmission System, Reinforcement (11.4 km of NPS 10)	2026	2.2	25.0	Mandatory: Reinforcement Specified per Network Analysis
	Ingersoll Transmission Station Rebuild	2022	8.4	8.4	Mandatory: Reinforcement Specified per Network Analysis

.

Asset Class	Project Name	In-Service Year	2021-2025 Net Capital ($M)	Total Net Capital ($M)	Driver
	SUDB: Marten River Compression Reinforcement	2023	51.6	51.6	Mandatory: Reinforcement Specified per Network Analysis
Distribution Pipe	NPS 8 Port Stanley Replacement	2024	20.6	20.6	Condition
	INTE: North Shore - Section A: Retrofit ECDA to ILI	2021	12.0	12.3	Mandatory: Retrofit for TIMP program (ILI Compliance)
	LOND - London Lines Replacement	2021	106.2	110.3	Condition
	Kirkland Lake Lateral Replacement	2022	16.8	16.8	Condition
Compression Stations	Dawn Plant-C Compression Life Cycle	2024	131	131	Obsolescence
	Waubuno Compression Life Cycle	2024	12.9	12.49	Obsolescence
Transmission Pipe and Storage	Panhandle Line Replacement	2023	29.8	29.8	Condition, High Consequence
	INTE: Dawn - Cuthbert - ECDA to ILI Retrofit NPS 42, 34, 26	2022	24.6	25.0	Mandatory: Retrofit for TIMP program (ILI Compliance)
	Dawn Parkway Expansion (Kirkwall-Hamilton NPS 48)	2022	176.1	181.7	Growth
	Sarnia Expansion (NPS 20 Dow to Bluewater)	2021	19.2	20.5	Growth
	Sarnia Expansion (Novacor Station)		6.5	6.5	
	Sarnia Expansion - Bluewater Energy Park (Asset #1)	2024	64.5	64.6	Growth
	Sarnia Expansion Project- Bluewater Energy Park (Customer Station)		11.7	11.7	
	Sarnia Expansion - Bluewater Energy Park (Asset #2)		34.0	34	
REWS	Thunder Bay Regional Operations Centre	2025	10.2	10.2	Condition
	New Site No. 4	2023	28.8	28.8	Operations Site Consolidation

Note: Dismantlement costs are not included in Total In-Service Capital.

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Plus Attachment

ENBRIDGE GAS INC.

Undertaking Response to EP

To provide an illustrative example of the evaluation process that Enbridge would use to compare a hypothetical transmission project with an alternative where a demand response program is implemented that decreases the size of the transmission project by 20 percent.

Response:

Please see Attachment 1 for the requested illustrative example.

Illustrative Demand Response vs Pipeline Example

	Pipeline				IRPA					
	Pipeline NPV	**Capacity Created (m3/hr)**	**NPV per Unit ($/m3/hr)**	**Stage 1 PI**	**Demand Response NPV**	**80% Pipeline NPV**	**Net IRPA NPV**	**Capacity Created (m3/hr)**	**NPV per Unit ($/m3/hr)**	**Stage 1 PI**
	(a)	(b)	(c) = (a) / (b)		(d)	(e)	(f) = (d) + (e)	(g)	(h) = (f) / (g)	
Stage 1	AAA	100	A.AA	PI	XXX	AAA	AXA	100	A.XA	PI
Stage 2	BBB	100	B.BB	n/a	YYY	BBB	YBY	100	Y.BY	n/a
Stage 3	CCC	100	C.CC	n/a	ZZZ	CCC	ZCZ	100	Z.CZ	n/a
Total	ABC	100	A.BC	n/a	XYZ	ABC	XYC	100	X.YC	n/a

Notes:

1 DCF analysis that would be used to evaluate the NPV of a typical Demand Response program that decreases the size of a transmission project by 20 percent.
2 Evaluation horizon of 40 years.
3 Calculated NPV is divided by capacity created to determine the cost per unit of capacity.
4 The test will be evaluated at each stage as well as the total of all stages.

Stage 1 DCF Analysis

Illustrative Demand Response Example

Project Year ($000's)	Notes / Examples	Project Total	1	2	3	…..	40
Operating Cash Flow							
Benefits:							
Incremental Revenues	Incremental transmission revenue received by Utility accounting for IRPA impact. Does not include gas commodity revenue.	XXX	XXX	XXX	XXX	XXX	XXX
Avoided Commodity/Fuel Costs		-	-	-	-	-	-
Avoided O&M & Municipal Tax	Lower municipal taxes from decreased size of transmission project.	XXX	XXX	XXX	XXX	XXX	XXX
Total Benefits		XXX	XXX	XXX	XXX	XXX	XXX
Costs:							
Incremental O&M	Includes Demand Response program costs (e.g. enrollment rebates, customer incentives).	XXX	XXX	XXX	XXX	XXX	XXX
Incremental Municipal Tax		-	-	-	-	-	-
Incremental Commodity/ Fuel Costs		-	-	-	-	-	-
Incremental Income Tax	Income tax effect from avoided municipal taxes and incremental O&M.	XXX	XXX	XXX	XXX	XXX	XXX
Total Costs		XXX	XXX	XXX	XXX	XXX	XXX
Net Operating Benefit/Cost		XXX	XXX	XXX	XXX	XXX	XXX
Capital							
Avoided Infrastructure Costs	Lower capital costs from decreased size of transmission project.	(XXX)	(XXX)	-	-	-	-
Change in Working Capital		-	-	-	-	-	-
Total Capital		(XXX)	(XXX)	-	-	-	-
CCA Tax Shield							
CCA Tax Shield	Lower CCA tax shield resulting from avoided infrastructure costs.	XXX	XXX	-	-	-	-
Net Present Value							
PV of Operating Cash Flow		XXX	XXX	XXX	XXX	XXX	XXX
PV of Capital		XXX	XXX	-	-	-	-
PV of CCA Tax Shield		(XXX)	(XXX)	(XXX)	(XXX)	(XXX)	(XXX)
Total NPV by Year		XXX	XXX	XXX	XXX	XXX	XXX
Project NPV	Discounted using a discount rate equal to the Utility's incremental after-tax cost of capital.	**XXX**					

Stage 2 DCF Analysis

Illustrative Demand Response Example

Project Year ($000's)	Notes / Examples	Project Total	1	2	3	…..	40
Operating Cash Flow							
Benefits:							
Avoided Infrastructure Costs		-	-	-	-	-	-
Avoided Commodity/Fuel Costs	Reduced costs incurred by customer due to annual reduction in consumption. Would not include load shifting (i.e. lower peak day consumption offset by higher consumption during off peak periods).	YYY	YYY	YYY	YYY	YYY	YYY
Avoided GHG Emission	Reduced Federal Carbon Charge associated with Avoided Commodity/Fuel Costs identified above.	YYY	YYY	YYY	YYY	YYY	YYY
Total Benefits		YYY	YYY	YYY	YYY	YYY	YYY
Costs:							
Incremental Customer Costs	Costs incurred by customer net of any rebates/incentives received from the Utility.	YYY	YYY	YYY	YYY	YYY	YYY
Incremental Commodity/ Fuel Costs	Costs incurred by customer due to the use of an alternative fuel to mitigate reduced use of natural gas.	YYY	YYY	YYY	YYY	YYY	YYY
Incremental GHG Emissions	Federal Carbon Charge associated with use of an alternative fuel identified above if applicable.	YYY	YYY	YYY	YYY	YYY	YYY
Total Costs		YYY	YYY	YYY	YYY	YYY	YYY
Net Operating Benefit/Cost		YYY	YYY	YYY	YYY	YYY	YYY
Net Present Value							
Total NPV by Year		YYY	YYY	YYY	YYY	YYY	YYY
Project NPV	Discounted using a societal discount rate (currently 4%).	**YYY**					

Stage 3 DCF Analysis

Illustrative Demand Response Example

Project Year ($000's)	Notes / Examples	Project Total	1	2	3	…..	40
Operating Cash Flow							
Benefits:							
Other External Non-Energy Benefits	Quantifiable benefits such as GDP impact and jobs created to be included. Current DSM assumption is that the societal benefit is 15% of identified customer benefits.	ZZZ	ZZZ	ZZZ	ZZZ	ZZZ	ZZZ
Total Benefits		ZZZ	ZZZ	ZZZ	ZZZ	ZZZ	ZZZ
Costs:							
Other External Non-Energy Costs	Unlikely to identify quantifiable societal costs associated with a Demand Response program.	-	-	-	-	-	-
Total Costs		-	-	-	-	-	-
Net Operating Benefit/Cost		ZZZ	ZZZ	ZZZ	ZZZ	ZZZ	ZZZ
Net Present Value							
Total NPV by Year		ZZZ	ZZZ	ZZZ	ZZZ	ZZZ	ZZZ
Project NPV	Discounted using a societal discount rate (currently 4%).	**ZZZ**					

Stage 1 DCF Analysis

Illustrative Pipeline Example

Project Year ($000's)	Notes / Examples	Project Total	1	2	3	.....	40
Operating Cash Flow							
Benefits:							
Incremental Revenues	Incremental transmission revenue received by Utility. Does not include gas commodity revenue.	AAA	AAA	AAA	AAA	AAA	AAA
Avoided Commodity/Fuel Costs		-	-	-	-	-	-
Avoided O&M & Municipal Tax		-	-	-	-	-	-
Total Benefits		-	-	-	-	-	-
Costs:							
Incremental O&M	Incremental O&M to maintain pipeline.	AAA	AAA	AAA	AAA	AAA	AAA
Incremental Municipal Tax	Incremental municipal tax paid for pipeline.	AAA	AAA	AAA	AAA	AAA	AAA
Incremental Commodity/ Fuel Costs		-	-	-	-	-	-
Incremental Income Tax	Income tax effect from incremental revenue, municipal taxes, and O&M.	AAA	AAA	AAA	AAA	AAA	AAA
Total Costs		AAA	AAA	AAA	AAA	AAA	AAA
Net Operating Benefit/Cost		AAA	AAA	AAA	AAA	AAA	AAA
Capital							
Incremental Infrastructure Costs	Capital costs for new pipeline.	AAA	AAA	-	-	-	-
Change in Working Capital		-	-	-	-	-	-
Total Capital		AAA	AAA	-	-	-	-
CCA Tax Shield							
CCA Tax Shield	CCA tax shield associated with capital costs for new pipeline	AAA	AAA	-	-	-	-
Net Present Value							
PV of Operating Cash Flow		AAA	AAA	AAA	AAA	AAA	AAA
PV of Capital		AAA	AAA	-	-	-	-
PV of CCA Tax Shield		AAA	AAA	AAA	AAA	AAA	AAA
Total NPV by Year		AAA	AAA	AAA	AAA	AAA	AAA
Project NPV	Discounted using a discount rate equal to the Utility's incremental after-tax cost of capital.	**AAA**					

Stage 2 DCF Analysis

Illustrative Pipeline Example

Project Year ($000's)	Notes / Examples	Project Total	1	2	3	.....	40
Operating Cash Flow							
Benefits:							
Avoided Infrastructure Costs		-	-	-	-	-	-
Avoided Commodity/Fuel Costs	Reduced costs incurred by customer associated with non-use of alternative fuels such as fuel oil, propane, electricity.	BBB	BBB	BBB	BBB	BBB	BBB
Avoided GHG Emission	Reduced Federal Carbon Charge associated with Avoided Commodity/Fuel Costs identified above if applicable.	BBB	BBB	BBB	BBB	BBB	BBB
Total Benefits		BBB	BBB	BBB	BBB	BBB	BBB
Costs:							
Incremental Customer Costs		-	-	-	-	-	-
Incremental Commodity/ Fuel Costs	Incremental natural gas costs incurred by customer.	BBB	BBB	BBB	BBB	BBB	BBB
Incremental GHG Emissions	Federal Carbon Charge associated with use of incremental natural gas identified above.	BBB	BBB	BBB	BBB	BBB	BBB
Total Costs		BBB	BBB	BBB	BBB	BBB	BBB
Net Operating Benefit/Cost		BBB	BBB	BBB	BBB	BBB	BBB
Net Present Value							
Total NPV by Year		BBB	BBB	BBB	BBB	BBB	BBB
Project NPV	Discounted using a societal discount rate (currently 4%).	**BBB**					

Stage 3 DCF Analysis

Illustrative Pipeline Example

Project Year ($000's)	Notes / Examples	Project Total	1	2	3	.....	40
Operating Cash Flow							
Benefits:							
Other External Non-Energy Benefits	Benefits such as GDP impact, jobs created, and resiliency as back up energy source during power outages may be included.	CCC	CCC	CCC	CCC	CCC	CCC
Total Benefits		CCC	CCC	CCC	CCC	CCC	CCC
Costs:							
Other External Non-Energy Costs	No quantifiable societal costs have been included to date.	-	-	-	-	-	-
Total Costs		-	-	-	-	-	-
Net Operating Benefit/Cost		CCC	CCC	CCC	CCC	CCC	CCC
Net Present Value							
Total NPV by Year		CCC	CCC	CCC	CCC	CCC	CCC
Project NPV	Discounted using a societal discount rate (currently 4%).	**CCC**					

ENBRIDGE GAS INC.

Undertaking Response to ED

To provide an updated and revised version of IR STAFF 20 with more detail for avoided commodity-fuel costs and for infrastructure costs.

Response:

	Benefit/Cost	Stage 1	Stage 2	Stage 3
	Benefits			
	Incremental Revenues	x		
2	Avoided Utility Infrastructure Costs	x		
3	Avoided Customer Infrastructure Costs		x	
4	Avoided Utility Commodity/Fuel Costs	x		
5	Avoided Customer Commodity/Fuel Costs		x	
	Avoided O&M	x		
	Avoided GHG Emissions		x	
	Other External Non-Energy Benefits			x
	Costs			
1	Incremental Capital Expenditure	x		
1	Incremental O&M	x		
	Incremental Taxes	x		
4	Incremental Utility Commodity/Fuel Costs	x		
5	Incremental Customer Commodity/Fuel Costs		x	
	Incremental GHG Emissions		x	
	Incremental Customer Costs		x	
	Other External Non-Energy Costs			x

Notes:
(1) Capital & O&M is inclusive of program administrative costs.
(2) Avoided or reduced infrastructure capital costs of the Utility (e.g. use of smaller diameter pipe).
(3) Avoided or reduced infrastructure capital costs of the customer (e.g. reduced Contribution in Aid of Construction).
(4) Avoided or incremental fuel costs of the Utility (e.g. compressor fuel and unaccounted for gas).
(5) Avoided or incremental fuel costs of the customer (e.g. lower/higher natural gas use, lower/higher electricity use).

ENBRIDGE GAS INC.

Undertaking Response to GEC

To give Enbridge's view on whether it should include the impact of tax impacts on customers as part of Stage 2.

Response:

No, Enbridge is not proposing to include any tax impacts on customers as part of Stage 2. This is consistent with Enbridge Gas's past E.B.O.134 analyses.

ENBRIDGE GAS INC.

Answer to Interrogatory from
Green Energy Coalition (GEC)

INTERROGATORY

Question:

On p. 22, at the end of paragraph 43 of its reply evidence, Enbridge states that volatility in carbon emissions policy since 2016 make it unreasonable to “speculate” on the cost of future carbon emissions and that uncertainty regarding future efficiency programming and the timeline for commercialization of new low carbon technologies make forecasting of carbon emission reductions “even more challenging and unreliable.”

a. Is Enbridge effectively saying that because forecasting the effects of future climate policy is difficult that forecasts of gas infrastructure investment needs should be based solely on current policies – i.e., assuming they will not change? If not, please explain.
b. Is Enbridge suggesting that analyses of the cost-effectiveness of non-pipe alternatives (relative to gas infrastructure investments) should be based solely on cost impacts under current policies, ignoring entirely – in cost-effectiveness calculations at least – how future changes in climate policies might alter cost-effectiveness? If not, please explain.
c. How does Enbridge propose to deal with uncertainty in the future cost forecasts of gas commodity, and of alternative fuel costs, and uncertainty of load in its IRPA analyses?

Response

a) Enbridge Gas does not forecast the effects of future climate policy where such future policy is not currently approved and set for future implementation. Enbridge Gas prudently develops its planning processes with consideration of OEB-approved methodologies and policies that are in place where impacts are known and quantifiable. This approach is done with the intention of mitigating unnecessary customer costs and risks where possible.

b) Enbridge Gas does not speculate on future changes in climate policies and their hypothetical impact to the analyses of IRPA(s), nor does the Company suggest that as these policies come to light there is no basis for further consideration or adjustment of IRP-related cost-effectiveness analyses.

Rather, Enbridge Gas supports Recommendation 4 of OEB Staff's expert evidence (the Guidehouse Report) set out at page 5 of the Guidehouse Report, which states:

> "It is recognized that the OEB considers provincial policy in its decision-making and is guided by statutory objectives (including a statutory objective related to natural gas to promote energy conservation and energy efficiency in accordance with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances). To the extent that the OEB is providing direction that may influence or be impacted by provincial environmental and policy goals, the OEB should clearly define their underlying assumptions regarding applicable provincial policy goals. For example, since future gas demand scenarios are likely to be impacted by energy and environmental policy, clearly defining underlying assumptions relating to provincial climate change policies and decarbonization targets will help to better inform gas network infrastructure decisions going forward."

c) The uncertainty referenced by GEC is not novel or unique to this proceeding. In fact, over the past two decades alone, natural gas commodity and alternative fuel prices (both spot and forecast) have fluctuated significantly due to forecasted natural gas supply shortfall risks driven by declines in traditional North American natural gas production followed by discovery and production of vast quantities of unconventional North American natural gas supply which became accessible due to advances in natural gas production technology. Further, as noted by GEC and set out in Enbridge Gas's Reply Evidence at Section 6.0, in 2016 the Ontario government put in place a Cap and Trade program which placed a price on emissions associated with volumes delivered by Enbridge Gas to ratepayers. That program was subsequently cancelled in 2018 and then replaced nearly a year later by a federal program in 2019. Throughout this period, despite the volatility in forecast prices and volumes, Enbridge Gas brought applications for Leave-to-Construct facilities to the Board for review and approval. As part of its review of those applications, the Board effectively and efficiently considered market conditions (both current and forecast) as well as the underlying Need for proposed facilities based on the best information available at the time. Enbridge Gas is proposing that the Board continue this best practice, by establishing an IRP Framework for Enbridge Gas that includes a means for assessing the cost-effectiveness of facility and non-facility alternatives based on the best available known and quantifiable costs, benefits and policies at the time that Enbridge Gas applies to the OEB for approval to invest in and to recover the costs associated with IRPAs.

Enbridge Gas's forecasting practices and proposal are similarly not unique to IRP. Enbridge Gas uniformly ascribes to the principles set out in its Reply Evidence at page 23:

"Only where the information concerning such policy and initiatives is known to be certain is it reasonable to forecast. Doing so based on a variety of hypothetical assumptions at a certain point in time [now as part of the development of an IRP Framework for Enbridge Gas], as recommended by EFG, would not produce information that is helpful or relevant to the Board in its review of future applications by Enbridge Gas for approvals related to either IRP or LTC investments as it would be entirely unreliable [and thus require adjustment in each such instance anyway]."

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ENBRIDGE GAS INC.

Undertaking Response to GEC

(a) to provide in-franchise customers a hundred percent shielded from the costs and risks of pipe investments needed, in whole or in part, to serve ex-franchise demand;

(b) if demand from ex-franchise customers is ultimately lower than forecast, do your arrangements with ex-franchise customers require them to still pay for their original share of the cost of system infrastructure investment over the full period over which the costs are to be recovered.

Response:

a) Ex-franchise shippers are largely served by the Dawn Parkway System. The Dawn Parkway System is used to serve the demands of both in-franchise and ex-franchise customers and the costs are allocated to rate classes based on the Dawn to Parkway distance weighted design day demands of both in-franchise and ex-franchise customers. When investments are made in the Dawn Parkway System, the associated costs are allocated to both in-franchise and ex-franchise customers based on their use of the Dawn Parkway System.

b) At each cost of service, Enbridge Gas will allocate and recover the costs of the Dawn Parkway System from the forecast of in-franchise and ex-franchise demands at that time. Ex-franchise customers pay the approved Dawn-Parkway rates for the term of their contract.

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ENBRIDGE GAS INC.

Answer to Interrogatory from
OEB Staff ("STAFF")

INTERROGATORY

Reference:

Exhibit B / pp. 21-30 of 46

Preamble:

Enbridge Gas describes a range of potential IRPA technologies.

Question:

a) Does Enbridge Gas have a view as to which of the described technologies appear most promising in the Ontario context in terms of deferring or avoiding Enbridge Gas infrastructure, considering cost-effectiveness, reliability, demand reduction potential, etc.?
b) In addition to their ability to reduce infrastructure costs (primarily by reducing peak demand), these technologies differ in the additional costs and benefits they would provide to customers and society (e.g. impact on customer commodity costs and carbon charges, etc.) Would Enbridge Gas's opinion as to which technologies would be most promising for IRP in Ontario change if the OEB determines that IRP cost-effectiveness should be assessed primarily from the viewpoint of customers or society, instead of from the utility perspective (e.g. using a Total Resource Cost+ test or Societal Cost Test)?

Response

a) & b)
Enbridge Gas has proposed several innovative natural gas and non-gas alternatives to resolve identified system constraints in its Additional Evidence.[1] Each alternative offers unique potential to resolve identified constraints in differing circumstances.

[1] Additional Evidence, pp. 21-30.

For example, GSHPs may be a good option for remote communities or new construction, however, GSHPs may be challenging to retrofit existing homes or commercial buildings. On the other hand, EASHPs may offer a good solution for heating during shoulder months, however, they may contribute to a peak in electric demand, increasing gas demand on the natural gas grid during a cold winter day when supplement/auxiliary heating will be provided with resistant heating. Although the efficiency of resistance heating is considered to be 100% at site, the source efficiency of marginal electricity produced from gas plants during winter peak will be about 40% as compared to a 95% efficiency of gas furnaces. Lastly, NGASHP are a good alternative to reducing peak natural gas demand on a consistent basis for both the retrofit and new construction market as their efficiency stays above the efficiency of a condensing furnace.

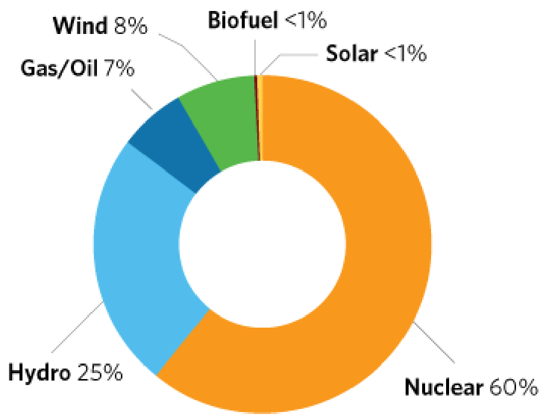
At such time that the OEB establishes an IRP Framework for Enbridge Gas and the Company subsequently identifies system constraints that can be resolved through investment in IRPAs, Enbridge Gas expects that the nature of those constraints, together with stakeholder feedback, and the unique environmental, policy and market conditions present at that time will inform its investigation into and potential selection of IRPAs.

Enbridge Gas also expects that the guidance set out within the IRP Framework ultimately established by the Board, including with regard to alternative cost-effectiveness tests, will also impact the viability of certain of the IRPAs proposed by the Company. However, at this time it is not possible to comment on all of the various possible variations to OEB guidance and their resulting impact upon the many potential IRPAs contemplated.

https://www.ieso.ca/en/Power-Data/Supply-Overview/Transmission-Connected-Generation

Yearly Energy Output by Fuel Type

The graph and figures below report the yearly 2020 output by fuel type. It includes facilities as reported through the real-time supply output above, as well as facilities with installed capacity of less than 20 MW that are transmission-connected. These figures do not include embedded generation. More information on embedded generation can be found in the distribution-connected generation section.



Nuclear	87.8 TWh or 60%
Hydro	36.9 TWh or 25%
Gas/Oil	9.7 TWh or 7%
Wind	11.8 TWh or 8%
Biofuel	0.4 TWh or <1%
Solar	0.8 TWh or <1%

https://www.geappliances.com/ductless/

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