EB-2022-0157

Enbridge Gas Inc.
Panhandle Reinforcement

POLLUTION PROBE
HEARING COMPENDIUM

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would install. Is that fair?

MR. NEME: Heating and water heating equipment, both, yes.

MR. STEVENS: And that the proposition is the customer is unlikely to switch; while it is expensive, HVAC equipment is still running well, but, when the customer comes to a replacement decision, that is when they may determine that they would adopt electric heat. Do I have that right?

MR. NEME: Yes, I would say that they are more likely to switch at the time or close to the time that their heating system would need be replaced anyway. It's possible that they may want to switch earlier, depending on government policies that could arise or changes in fuel prices and so on, but it is more likely that it will be close to the time that they would otherwise replace their heating system.

MR. STEVENS: Right, and you have said in your report that the life of a new furnace is 18 years. That is at page 43. Do I have that right?

MR. NEME: That is the best estimate that is currently being used or has historically been used in your DSM programs.

MR. STEVENS: And furnaces can run longer than that. Right?

MR. NEME: Sure, and they can run shorter than that. That is an average.

MR. STEVENS: Right. And it is not case that -- we

OEB-APPROVED ADDITIONAL MEASURE INCENTIVES FOR JOINT RESIDENTIAL WHOLE HOME PROGRAM

NRCan Canada Greener Homes Grant Measures	NRCan Incentive	EGI Proposed Enhanced Incentive	OEB-Approved Measures	OEB-Approved Incentives for EGI	Total Enhanced Incentive (NRCan + OEB-Approved EGI)
Energy Audits			**Energy Audits**		
ENERGuide Pre & Post Evaluations	$600	$0	ENERGuide Pre & Post Evaluations	$0	$600
Attic/Cathedral Insulation			**Attic/Cathedral Insulation**		
Increase attic insulation to at least R50 from less than R12	$1,800	$200	Increase attic insulation to at least R50 from less than R12	$550	$2,350
Increase attic insulation to at least R50 from greater than R12 up to R25	$600	$400	Increase attic insulation to at least R50 from greater than R12 up to R25	$200	$800
Increase attic insulation to at least R50 from greater than R25 up to R35	$250	$600	Increase attic insulation to at least R50 from greater than R25 up to R35	$75	$325
Increase cathedral/flat roof insulation to at least R-28 from R12 or less	$600	$400	Increase cathedral/flat roof insulation to at least R-28 from R12 or less	$200	$800
Increase cathedral/flat roof insulation to at least R-28 from greater than R12 up to R25	$250	$600	Increase cathedral/flat roof insulation to at least R-28 from greater than R12 up to R25	$75	$325
Upgrade uninsulated cathedral ceiling/flat roof to at least R20 from R12 or less	$600	$400	Upgrade uninsulated cathedral ceiling/flat roof to at least R20 from R12 or less	$200	$800
Exterior Wall Insulation			**Exterior Wall Insulation**		
For adding insulation value of at least greater than R20 for 100% of building	$5,000	$2,500	For adding insulation value of at least greater than R20 for 100% of building	$1,750	$6,750
For adding insulation value greater than R12 up to R20 to 100% of the building	$3,800	$1,700	For adding insulation value greater than R12 up to R20 to 100% of the building	$1,200	$5,000
For adding insultation value greater than R7.5 up to R12 for 100% of building	$3,300	$1,200	For adding insultation value greater than R7.5 up to R12 for 100% of building	$1,200	$4,500
Exposed Floor Insulation			**Exposed Floor Insulation**		
For adding insulation value of at least R20 for entire exposed area (minimum area of 11 square meters or 120 square feet)	$350	$150	For adding insulation value of at least R20 for entire exposed area (minimum area of 11 square meters or 120 square feet)	$100	$450
Basement Insulation			**Basement Insulation**		
For sealing and insulating at least 80% of basement header to a minimum R20	$240	$110	For sealing and insulating at least 80% of basement header to a minimum R20	$85	$325
For sealing and insulating at least 50% of the entire basement slab by a minimum of R3.5	$400	$200	For sealing and insulating at least 50% of the entire basement slab by a minimum of R3.5	$150	$550
For adding insulation value greater than R22 to 100% of basement	$1,500	$1,000	For adding insulation value greater than R22 to 100% of basement	$500	$2,000

NRCan Canada Greener Homes Grant Measures	NRCan Incentive	EGI Proposed Enhanced Incentive	OEB-Approved Measures	OEB-Approved Incentives for EGI	Total Enhanced Incentive (NRCan + OEB-Approved EGI)
For adding insulation value of R10 to R22 to 100% of basement	$1,050	$450	For adding insulation value of R10 to R22 to 100% of basement	$350	$1,400
For adding insulation value of R10 to R22 to 100% of exterior crawl space wall area, including header	$1,300	$700	For adding insulation value of R10 to R22 to 100% of exterior crawl space wall area, including header	$400	$1,700
For adding insulation value of R10 to R22 to 100% of exterior crawl space wall area, including header	$1,040	$460	For adding insulation value of R10 to R22 to 100% of exterior crawl space wall area, including header	$360	$1,400
For adding insulation value greater than R24 to 100% of crawl space ceiling	$800	$400	For adding insulation value greater than R24 to 100% of crawl space ceiling	$250	$1,050
Furnace/Boiler			**Furnace/Boiler**		
N/A	N/A	.N/A	N/A	N/A	N/A
Space Heating Heat Pump			**Space Heating Heat Pump**		
Install a ground source heat pump – full system.	$5,000	$0	Install a ground source heat pump – full system.	$1,500	$6,500
Replace a ground source heat pump – heat pump unit only.	$3,000	$0	Replace a ground source heat pump – heat pump unit only.	$1,000	$4,000
Install a complete ENERGY STAR certified new or replacement air source heat pump (ASHP) system or a variable capacity cold climate air source heat pump (ccASHP) system. The system must be intended to service the entire home.	$2,500	$0	Install a complete ENERGY STAR certified new or replacement air source heat pump (ASHP) system or a variable capacity cold climate air source heat pump (ccASHP) system. The system must be intended to service the entire home.	$750	$3,250
Install a complete ENERGY STAR certified new or replacement air source heat pump (ASHP) system, intended to service the entire home.	$4,000	$0	Install a complete ENERGY STAR certified new or replacement air source heat pump (ASHP) system, intended to service the entire home.	$1,250	$5,250
Install a complete new or replacement variable capacity cold climate air source heat pump (ccASHP) system, intended to service the entire home.	$5,000	$0	Install a complete new or replacement variable capacity cold climate air source heat pump (ccASHP) system, intended to service the entire home.	$1,500	$6,500
Water Heating			**Water Heating**		
Replace domestic water heater with an ENERGY STAR certified domestic hot water heat pump (DHW-HP)	$1,000	$0	Replace domestic water heater with an ENERGY STAR certified domestic hot water heat pump (DHW-HP)	$300	$1,300
Windows & Doors			**Windows & Doors**		
Replace windows or sliding glass doors with ENERGY STAR most efficient models.	$250	$0	Replace windows or sliding glass doors with ENERGY STAR most efficient models.	$75	$325
Replace windows or sliding glass doors with ENERGY STAR certified models.	$125	$0	Replace windows or sliding glass doors with ENERGY STAR certified models.	$50	$175
Replace hinged doors, with or without sidelites or transoms with ENERGY STAR certified models.	$125	$0	Replace hinged doors, with or without sidelites or transoms with ENERGY STAR certified models.	$50	$175

NRCan Canada Greener Homes Grant Measures	NRCan Incentive	EGI Proposed Enhanced Incentive	OEB-Approved Measures	OEB-Approved Incentives for EGI	Total Enhanced Incentive (NRCan + OEB-Approved EGI)
Air Sealing			**Air Sealing**		
Achieve base target	$550	$0	Achieve base target	$175	$725
Achieve 10% or more above base target	$810	$0	Achieve 10% or more above base target	$240	$1,050
Achieve 20% or more above base target	$1,000	$0	Achieve 20% or more above base target	$300	$1,300
Renewable Energy System			**Renewable Energy System**		
Install solar panels (photovoltaic (PV) system) ≥ 1.0 kW	$1,000 per kW	$0	N/A	$0	$1,000 per kW
Resiliency Measures			**Resiliency Measures**		
Batteries connected to Photovoltaic systems	$1,000	$0	Batteries connected to Photovoltaic systems	$0	N/A
Roofing Membrane	$150	$0	Roofing Membrane	$0	N/A
Foundation water-proofing	$875	$0	Foundation water-proofing	$0	N/A
Moisture proofing crawl space floor, walls and headers	$600	$0	Moisture proofing crawl space floor, walls and headers	$0	N/A
Thermostat			**Thermostat**		
Replace a manual thermostat with a programmable thermostat	$50		Replace a manual thermostat with a programmable thermostat	$20	$70
Replace a manual thermostat with a adaptive thermostat (Natural gas heated participants in the Enbridge franchise area are eligible for an ehanced $75 rebate (or $125 rebate if Moderate Income eligible), all other participants eligible for $50 rebate.	$50	$75	Replace a manual thermostat with a adaptive thermostat (Natural gas heated participants in the Enbridge franchise area are eligible for an ehanced $75 rebate (or $125 rebate if Moderate Income eligible), all other participants eligible for $50 rebate.	$75	$125
Multi Measure Bonus			**Multi Measure Bonus**		
N/A	$0		N/A	N/A	N/A

ENBRIDGE GAS INC.

Answer to Undertaking from
School Energy Coalition (SEC)

Undertaking

Tr: 78

Subject to data availability, to provide responses to the portions of SEC-119(a) that were previously declined

Response:

The requested information is unavailable in some instances and, in others, will require an onerous amount of data extraction that is not possible to complete within the timeframe provided for undertaking responses.

Further, as indicated in the response at Exhibit I.1.12-FRPO-21, certain information requested by SEC bears no relevance to the current Application because Enbridge Gas has not included any forecasted capital costs or revenue requirement adjustments associated with actual attachments to date for its community expansion projects in its proposed 2024 rate base; only the original forecast project costs have been included.

Enbridge Gas will report on the actual capital costs, actual customer attachments, and final project PI through future rebasing applications, following completion of the 10-year rate stabilization period(s) (RSP) and attachment forecast term(s) associated with each community expansion project, in accordance with the OEB's determinations in prior applications, including the Company's SES/TCS/HAF Application[1].

Updated Response: /u

Pursuant to Enbridge Gas's letter dated April 11, 2023, in relation to Motions Day, please see below for the information sought in Exhibit I.2.6-SEC199 a)/Undertaking Exhibit JT3.16.

Table 1 summarizes the requested information for Community Expansion projects in execution to date. Additional information is available in Attachment 1 for all Community Expansion projects to date.

[1] EB-2020-0094, Decision and Order, November 5, 2020, sections 3.2 and 3.3.

Table 1

(i) Project Name	(ii) Budgeted Capital Cost ($)(1)	(iii) Forecast Cost ($)(2)	(iv) Actual Capital Cost-to-date ($)	(v) Forecast Final Capital Cost ($)(3)	(vi) 10-year Forecast Customer Attachments (Total)(4)	(vii) Actual Customer attachments to date (Total)(4)	(viii) Original Forecast PI	(ix) Revised Forecast PI (based on most recent forecast cost)	(x) SES Term	(xi) Shortfall if the current Forecast PI is less than 1.0 ($)(5)
Milverton and Rostock/Wartburg	5,976,000	5,976,000	7,008,147	9,117,941	739	761	1.01	1.14	15	
Kettle and Stoney Point First Nation and Lambton Shores	2,095,000	2,095,000	2,097,092	2,884,545	364	394	1.03	0.90	12	328,155
Delaware Nation of Moraviantown	564,000	564,000	$628,615	628,615	38	38	1.00	1.25	40	-
Prince Township	2,721,000	2,721,000	2,427,968	2,765,254	291	224	1.01	1.06	22	-
Fenelon Falls	46,878,981	46,878,981	55,493,796	64,425,880	1920	866	1.00	0.50	40	28,667,344
Chippewa of the Thames First Nation	1,863,000	1,863,000	1,169,065	1,244,199	45	49	1.00	1.00 (6)	40	
Saugeen First Nation	2,536,617	2,536,617	3,069,824	3,571,108	89	33	1.00	0.47	40	1,036,969
Northshore and Peninsula Rd	10,095,411	10,095,411	12,057,826	12,156,459	134	161	1.00	0.64	40	1,355,698
Scugog Island First Nation	16,550,837	16,550,837	27,714,665	32,177,771	810	454	1.00	0.52	40	12,896,120
Brunner (Perth East)	2,210,351	1,293,836	1,019,042	1,050,898	44	42	1.00	2.98	40	-
Burk's Falls	1,653,917	1,653,917	1,160,701	1,734,353	41	11	1.00	0.96	40	19,929
Kenora District (Highway 594)	1,551,582	1,551,582	1,785,436	1,803,174	30	35	1.00	0.55	40	448,867
Stanley's Olde Maple	820,779	820,779	830,674	838,714	11	12	1.00	0.78	40	118,874

Table 1 Continued

(i) Project Name	(ii) Budgeted Capital Cost ($)(1)	(iii) Forecast Cost ($)(2)	(iv) Actual Capital Cost-to-date ($)	(v) Forecast Final Capital Cost ($)(3)	(vi) 10-year Forecast Customer Attachments (Total)(4)	(vii) Actual Customer attachments to date (Total)(4)	(viii) Original Forecast PI	(ix) Revised Forecast PI (based on most recent forecast cost)	(x) SES Term	(xi) Shortfall if the current Forecast PI is less than 1.0 ($)(5)
Haldimand Shores	4,048,709	4,048,709	3,261,207	4,281,580	112	59	1.00	0.98	40	32,528
Mohawk of Bay of Quinte	10,715,495	10,715,495	-	10,715,495	179	-	1.00	-	40	-
Hidden Valley	3,463,661	3,339,388	-	3,339,388	110	-	1.00	-	40	-
Selwyn	6,041,151	4,502,425	-	4,502,425	87	-	1.00	-	40	-

Notes:

(1) The budgeted cost is based on the original estimated capex for the project

(2) The forecast cost is based on updated estimated capex (e.g., LTC filed project cost if applicable)

(3) The forecast final capital cost is based on the projected number of attachments. Attachments numbers are subject to change in the remaining year during the 10-year rate stability period

(4) The annual forecast and actuals customer attachments are provided in Attachment I

(5) for part (xi), the shortfall amount is based on the additional capital funding required and not the required revenue forecast shortfall to achieve a PI of 1.0

(6) The PI cannot be calculated as the current projected final capital cost is lower than the available funding of $1,430,000. However, the rate stability period has yet to be concluded, and additional customers might be attached, which might drive the final cost to exceed the available funding.

Enbridge Gas will report on the actual capital costs, actual customer attachments, and final project PI through future rebasing applications, following the completion of the 10-year rate stabilization period(s) (RSP) and attachment forecast term(s) associated with each community expansion project, in accordance with the OEB's determinations in prior applications, including the Company's SES/TCS/HAF Application[2].

Enbridge Gas cautions against making conclusions based on the information provided before completing the 10-year rate stabilization period associated with each community expansion project.

[2] EB-2020-0094, Decision and Order, November 5, 2020, sections 3.2 and 3.3.

(i) Milverton and Rostock/Wartburg Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 5,976,000
(iii) Forecast Cost ($) [2]	$ 5,976,000
(iv) Actual Capital Cost-to-date ($)	$ 7,008,147
(v) Forecast final Capital Cost ($) [3]	$ 9,117,941

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
(vi) Forecast Customer Attachments (#/yr)		185	163	67	51	42	50	44	50	45	42	739
(vii) Actual Customer Attachment (#/yr) - Installed Services	163	326	114	83	31	33	11					761

(viii) Oriiginal Forecast PI	1.01
(ix) Revised forecast PI based on the most recent forecast costs and customer attachment forecast	1.14
(x) SES term	15
(xi) If the PI in part (ix) is below 1.0, the forecast capital funding shortfall [4]	N/A

(i) Kettle and Stoney Point First Nation and Lambton Shores Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 2,095,000
(iii) Forecast Cost ($) [2]	$ 2,095,000
(iv) Actual Capital Cost-to-date ($)	$ 2,097,092
(v) Forecast final Capital Cost ($) [3]	$ 2,884,545

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
(vi) Forecast Customer Attachments (#/yr)	158	68	27	18	14	17	15	17	16	14	364
(vii) Actual Customer Attachment (#/yr) - Installed Services	68	182	66	35	27	11	5				394

(viii) Oriiginal Forecast PI	1.03
(ix) Revised forecast PI based on the most recent forecast costs and customer attachment forecast	0.90
(x) SES term	12
(xi) If the PI in part (ix) is below 1.0, the forecast capital funding shortfall [4]	$ 328,155

(i) Delaware Nation of Moraviantown Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 564,000
(iii) Forecast Cost ($) [2]	$ 564,000
(iv) Actual Capital Cost-to-date ($)	$ 628,615
(v) Forecast final Capital Cost ($) [3]	$ 628,615

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
(vi) Forecast Customer Attachments (#/yr)	23	5	2	2	1	1	1	1	1	1	38
(vii) Actual Customer Attachment (#/yr) - Installed Services	21	11	2	4	0	0					38

(viii) Oriiginal Forecast PI	1.00
(ix) Revised forecast PI based on the most recent forecast costs and customer attachment forecast	1.25
(x) SES term	40
(xi) If the PI in part (ix) is below 1.0, the forecast capital funding shortfall [4]	N/A

(i) Prince Township Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 2,721,000
(iii) Forecast Cost ($) [2]	$ 2,721,000
(iv) Actual Capital Cost-to-date ($)	$ 2,427,968
(v) Forecast final Capital Cost ($) [3]	$ 2,765,254

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
(vi) Forecast Customer Attachments (#/yr)	76	68	26	19	15	19	16	19	17	16	291
(vii) Actual Customer Attachment (#/yr) - Installed Services	145	40	17	13	9	0					224

(viii) Oriiginal Forecast PI	1.01
(ix) Revised forecast PI based on the most recent forecast costs and customer attachment forecast	1.06
(x) SES term	22
(xi) If the PI in part (ix) is below 1.0, the forecast capital funding shortfall [4]	N/A

(i) Fenelon Falls Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 46,878,981
(iii) Forecast Cost ($) [2]	$ 46,878,981
(iv) Actual Capital Cost-to-date ($)	$ 55,493,796
(v) Forecast final Capital Cost ($) [3]	$ 64,425,880

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
(vi) Forecast Customer Attachments (#/yr)		123	344	383	307	216	162	162	85	69	69	1,920
(vii) Actual Customer Attachment (#/yr) - Installed Services	67	484	205	49	45	16						866

(viii) Oriiginal Forecast PI	1.00
(ix) Revised forecast PI based on the most recent forecast costs and customer attachment forecast	0.50
(x) SES term	40
(xi) If the PI in part (ix) is below 1.0, the forecast capital funding shortfall [4]	$ 28,667,344

(i) Chippewa of the Thames First Nation Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 1,863,000
(iii) Forecast Cost ($) [2]	$ 1,863,000
(iv) Actual Capital Cost-to-date ($)	$ 1,169,065
(v) Forecast final Capital Cost ($) [3]	$ 1,244,199

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
(vi) Forecast Customer Attachments (#/yr)	20	18	1	1	1	1	1	1	1	0	45
(vii) Actual Customer Attachment (#/yr) - Installed Services	31	12	0	6	0						49

(viii) Oriiginal Forecast PI	1.00
(ix) Revised forecast PI based on the most recent forecast costs and customer attachment forecast [5]	1.00
(x) SES term	40
(xi) If the PI in part (ix) is below 1.0, the forecast capital funding shortfall [4]	N/A

(i) Saugeen First Nation Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 2,536,617
(iii) Forecast Cost ($) [2]	$ 2,536,617
(iv) Actual Capital Cost-to-date ($)	$ 3,069,824
(v) Forecast final Capital Cost ($) [3]	$ 3,571,108

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
(vi) Forecast Customer Attachments (#/yr)	30	27	8	6	3	3	3	3	3	3	89
(vii) Actual Customer Attachment (#/yr) - Installed Services	14	10	5	4							33

(viii) Oriiginal Forecast PI	1.00
(ix) Revised forecast PI based on the most recent forecast costs and customer attachment forecast	0.47
(x) SES term	40
(xi) If the PI in part (ix) is below 1.0, the forecast capital funding shortfall [4]	$ 1,036,969

(i) Northshore and Peninsula Rd Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 10,095,411
(iii) Forecast Cost ($) [2]	$ 10,095,411
(iv) Actual Capital Cost-to-date ($)	$ 12,057,826
(v) Forecast final Capital Cost ($) [3]	$ 12,156,459
(viii) Oriiginal Forecast PI	1.00
(ix) Revised forecast PI based on the most recent forecast costs and customer attachment forecast	0.64
(x) SES term	40
(xi) If the PI in part (ix) is below 1.0, the forecast capital funding shortfall [4]	$ 1,355,698

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
(vi) Forecast Customer Attachments (#/yr)	36	32	14	9	7	8	7	8	7	6	134
(vii) Actual Customer Attachment (#/yr) - Installed Services	69	81	11	0							161

(i) Scugog Island First Nation Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 16,550,837
(iii) Forecast Cost ($) [2]	$ 16,550,837
(iv) Actual Capital Cost-to-date ($)	$ 27,714,665
(v) Forecast final Capital Cost ($) [3]	$ 32,177,771
(viii) Oriiginal Forecast PI	1.00
(ix) Revised forecast PI based on the most recent forecast costs and customer attachment forecast	0.52
(x) SES term	40
(xi) If the PI in part (ix) is below 1.0, the forecast capital funding shortfall [4]	$ 12,896,120

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
(vi) Forecast Customer Attachments (#/yr)	79	211	207	110	50	38	38	33	22	22	810
(vii) Actual Customer Attachment (#/yr) - Installed Services	63	320	53	18							454

(i) Brunner (Perth East) Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 2,210,351
(iii) Forecast Cost ($) [2]	$ 1,293,836
(iv) Actual Capital Cost-to-date ($)	$ 1,019,042
(v) Forecast final Capital Cost ($) [3]	$ 1,050,898
(viii) Oriiginal Forecast PI	1.00
(ix) Revised forecast PI based on the most recent forecast costs and customer attachment forecast	2.98
(x) SES term	40
(xi) If the PI in part (ix) is below 1.0, the forecast capital funding shortfall [4]	N/A

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
(vi) Forecast Customer Attachments (#/yr)	11	13	7	5	3	1	1	1	1	1	44
(vii) Actual Customer Attachment (#/yr) - Installed Services	41	1									42

(i) Burk's Falls Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 1,653,917
(iii) Forecast Cost ($) [2]	$ 1,653,917
(iv) Actual Capital Cost-to-date ($)	$ 1,160,701
(v) Forecast final Capital Cost ($) [3]	$ 1,734,353
(viii) Oriiginal Forecast PI	1.00
(ix) Revised forecast PI based on the most recent forecast costs and customer attachment forecast	0.96
(x) SES term	40
(xi) If the PI in part (ix) is below 1.0, the forecast capital funding shortfall [4]	$ 19,929

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
(vi) Forecast Customer Attachments (#/yr)	12	14	5	3	2	1	1	1	1	1	41
(vii) Actual Customer Attachment (#/yr) - Installed Services	11	0									11

(i)Kenora District (Highway 594) Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 1,551,582
(iii) Forecast Cost ($) [2]	$ 1,551,582
(iv) Actual Capital Cost-to-date ($)	$ 1,785,436
(v) Forecast final Capital Cost ($) [3]	$ 1,803,174
(viii) Oriiginal Forecast PI	1.00
(ix) Revised forecast PI based on the most recent forecast costs and customer attachment forecast	0.55
(x) SES term	40
(xi) If the PI in part (ix) is below 1.0, the forecast capital funding shortfall [4]	$ 448,867

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
(vi) Forecast Customer Attachments (#/yr)	9	8	4	2	2	1	1	1	1	1	30
(vii) Actual Customer Attachment (#/yr) - Installed Services	35										35

(i) Stanley's Olde Maple Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 820,779
(iii) Forecast Cost ($) [2]	$ 820,779
(iv) Actual Capital Cost-to-date ($)	$ 830,674
(v) Forecast final Capital Cost ($) [3]	$ 838,714
(viii) Oriiginal Forecast PI	1.00
(ix) Revised forecast PI based on the most recent forecast costs and customer attachment forecast	0.78
(x) SES term	40
(xi) If the PI in part (ix) is below 1.0, the forecast capital funding shortfall [4]	$ 118,874

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
(vi) Forecast Customer Attachments (#/yr)	4	4	2	1	0	0	0	0	0	0	11
(vii) Actual Customer Attachment (#/yr) - Installed Services	12										12

(i) Haldimand Shores Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 4,048,709
(iii) Forecast Cost ($) [2]	$ 4,048,709
(iv) Actual Capital Cost-to-date ($)	$ 3,261,207
(v) Forecast final Capital Cost ($) [3]	$ 4,281,580
(viii) Oriiginal Forecast PI	1.00
(ix) Revised forecast PI based on the most recent forecast costs and customer attachment forecast	0.98
(x) SES term	40
(xi) If the PI in part (ix) is below 1.0, the forecast capital funding shortfall [4]	$ 32,528

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
(vi) Forecast Customer Attachments (#/yr)	30	27	10	7	6	7	6	7	6	6	112
(vii) Actual Customer Attachment (#/yr) - Installed Services	59										59

(i) Mohawk of Bay of Quinte Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 10,715,495											
(iii) Forecast Cost ($) [2]	$ 10,715,495											
(iv) Actual Capital Cost-to-date ($)	N/A											
(v) Forecast final Capital Cost ($) [3]	$ 10,715,495											
		2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
(vi) Forecast Customer Attachments (#/yr)		45	45	19	13	9	11	9	10	9	9	179
(vii) Actual Customer Attachment (#/yr) - Installed Services		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0
(viii) Oriiginal Forecast PI	1.00											
(ix) Revised forecast PI based on the most recent forecast costs and customer attachment forecast	N/A											
(x) SES term	40											
(xi) If the PI in part (ix) is below 1.0, the forecast capital funding shortfall [4]	N/A											

(i) Hidden Valley Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 3,463,661											
(iii) Forecast Cost ($) [2]	$ 3,339,388											
(iv) Actual Capital Cost-to-date ($)	N/A											
(v) Forecast final Capital Cost ($) [3]	$ 3,339,388											
		2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
(vi) Forecast Customer Attachments (#/yr)		29	26	10	7	6	7	6	7	6	6	110
(vii) Actual Customer Attachment (#/yr) - Installed Services		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0
(viii) Oriiginal Forecast PI	1.00											
(ix) Revised forecast PI based on the most recent forecast costs and customer attachment forecast	N/A											
(x) SES term	40											
(xi) If the PI in part (ix) is below 1.0, the forecast capital funding shortfall [4]	N/A											

(i) Selwyn Community Expansion Project

(ii) Budgeted Capital Cost($) [1]	$ 6,041,151											
(iii) Forecast Cost ($) [2]	$ 4,502,425											
(iv) Actual Capital Cost-to-date ($)	N/A											
(v) Forecast final Capital Cost ($) [3]	$ 4,502,425											
		2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**Total**
(vi) Forecast Customer Attachments (#/yr)		34	19	12	7	5	4	2	2	1	1	87
(vii) Actual Customer Attachment (#/yr) - Installed Services		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0
(viii) Oriiginal Forecast PI	1.00											
(ix) Revised forecast PI based on the most recent forecast costs and customer attachment forecast	N/A											
(x) SES term	40											
(xi) If the PI in part (ix) is below 1.0, the forecast capital funding shortfall [4]	N/A											

Notes:
1. The budgeted cost is based on the original estimated capex for the project
2. The forecast cost is based on updated estimated capex (e.g. LTC filed project cost if applicable)
3. The forecast final capital cost is based on the known projected number of attachments. Attachments numbers are subjected to change in the remaning year during the 10-years rate stability period
4. for part (xi) the shortfall amount is based on the additional capital required and not the required revenue forecast shortfall to achieve a PI of 1.0
5. For Chippewas FN project, the PI can not be calculated as the current projected final capital cost is lower than the available funding of $1,430,000. However, the rate stability period additional customers might be attached which might drive the final cost to exceed the available funding.

Cornwall Island First Nation Community Expansion Project

(ii) Budgeted Capital Cost($) $ 8,418,045

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(vi) Forecast Customer Attachments (#/yr)	38	97	94	48	20	13	13	13	9	9	354

(viii) Oriiginal Forecast PI 1.0
(x) SES term 40

Hiawatha First Nation Community Expansion Project

(ii) Budgeted Capital Cost($) $ 5,286,857

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(vi) Forecast Customer Attachments (#/yr)	29	59	57	16	14	10	10	8	5	5	213

(viii) Oriiginal Forecast PI 1.0
(x) SES term 40

Boblo Island Community Expansion Project

(ii) Budgeted Capital Cost($) $ 2,776,579

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(vi) Forecast Customer Attachments (#/yr)	28	21	14	7	7	3	3	3	3	3	92

(viii) Oriiginal Forecast PI 1.0
(x) SES term 40

Cedar Springs Community Expansion Project

(ii) Budgeted Capital Cost($) $ 3,479,788

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(vi) Forecast Customer Attachments (#/yr)	31	28	15	8	8	3	3	3	2	2	103

(viii) Oriiginal Forecast PI 1.0
(x) SES term 40

Neustadt Community Expansion Project

(ii) Budgeted Capital Cost($) $ 7,769,155

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(vi) Forecast Customer Attachments (#/yr)	50	62	24	13	11	13	11	12	12	11	219

(viii) Oriiginal Forecast PI 1.0
(x) SES term 40

Cherry Valley (Prince Edward County) Community Expansion Project

(ii) Budgeted Capital Cost($) $ 7,883,379

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(vi) Forecast Customer Attachments (#/yr)	41	44	24	11	11	5	4	4	4	4	152

(viii) Oriiginal Forecast PI 1.0
(x) SES term 40

Red Rock First Nation Community Expansion Project

(ii) Budgeted Capital Cost($) $ 4,081,700

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(vi) Forecast Customer Attachments (#/yr)	21	20	13	7	6	2	2	2	2	2	77

(viii) Oriiginal Forecast PI 1.0
(x) SES term 40

Severn (Washago) Community Expansion Project

(ii) Budgeted Capital Cost($) $ 28,859,544

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(vi) Forecast Customer Attachments (#/yr)	209	182	113	56	55	22	22	22	21	21	723

(viii) Oriiginal Forecast PI 1.0
(x) SES term 40

St. Charles Community Expansion Project

(ii) Budgeted Capital Cost($) $ 8,602,563

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(vi) Forecast Customer Attachments (#/yr)	44	46	24	14	14	4	4	4	4	4	162

(viii) Oriiginal Forecast PI 1.0
(x) SES term 40

Tweed Community Expansion Project

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(ii) Budgeted Capital Cost($)	$ 5,091,557											
(vi) Forecast Customer Attachments (#/yr)		16	19	9	4	4	2	2	2	2	2	62
(viii) Oriiginal Forecast PI	1.0											
(x) SES term	40											

Bobcaygeon Community Expansion Project

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(ii) Budgeted Capital Cost($)	$ 116,714,815											
(vi) Forecast Customer Attachments (#/yr)		429	562	388	565	541	444	429	218	205	198	3979
(viii) Oriiginal Forecast PI	1.0											
(x) SES term	40											

Caledon (Humber Station) Community Expansion Project

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(ii) Budgeted Capital Cost($)	$ 7,010,026											
(vi) Forecast Customer Attachments (#/yr)		25	25	11	7	5	6	5	6	5	5	100
(viii) Oriiginal Forecast PI	1.0											
(x) SES term	40											

Chute-a-Blondeau Community Expansion Project

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(ii) Budgeted Capital Cost($)	$ 9,038,505											
(vi) Forecast Customer Attachments (#/yr)		81	85	32	21	16	18	16	18	16	15	318
(viii) Oriiginal Forecast PI	1.0											
(x) SES term	40											

East Gwillimbury (North and East) Community Expansion Project

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(ii) Budgeted Capital Cost($)	$ 15,563,359											
(vi) Forecast Customer Attachments (#/yr)		106	109	41	29	23	27	21	24	22	20	422
(viii) Oriiginal Forecast PI	1.0											
(x) SES term	40											

Glendale Subdivision Community Expansion Project

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(ii) Budgeted Capital Cost($)	$ 3,753,588											
(vi) Forecast Customer Attachments (#/yr)		19	23	6	5	4	4	4	4	4	4	77
(viii) Oriiginal Forecast PI	1.0											
(x) SES term	40											

Lanark and Balderson Community Expansion Project

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(ii) Budgeted Capital Cost($)	$ 19,199,846											
(vi) Forecast Customer Attachments (#/yr)		76	91	36	23	17	20	18	20	17	16	334
(viii) Oriiginal Forecast PI	1.0											
(x) SES term	40											

Merrickville-Wolford Community Expansion Project

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(ii) Budgeted Capital Cost($)	$ 4,024,120											
(vi) Forecast Customer Attachments (#/yr)		16	19	7	5	3	4	3	4	3	3	67
(viii) Oriiginal Forecast PI	1.0											
(x) SES term	40											

Sandford Community Expansion Project

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Total
(ii) Budgeted Capital Cost($)	$ 6,631,637											
(vi) Forecast Customer Attachments (#/yr)		35	38	14	9	7	8	7	8	7	7	140
(viii) Oriiginal Forecast PI	1.0											
(x) SES term	40											

Panhandle Regional Expansion Project Incremental Capital Seeking Stage 3

Capital Allocation Committee

January 11, 2023

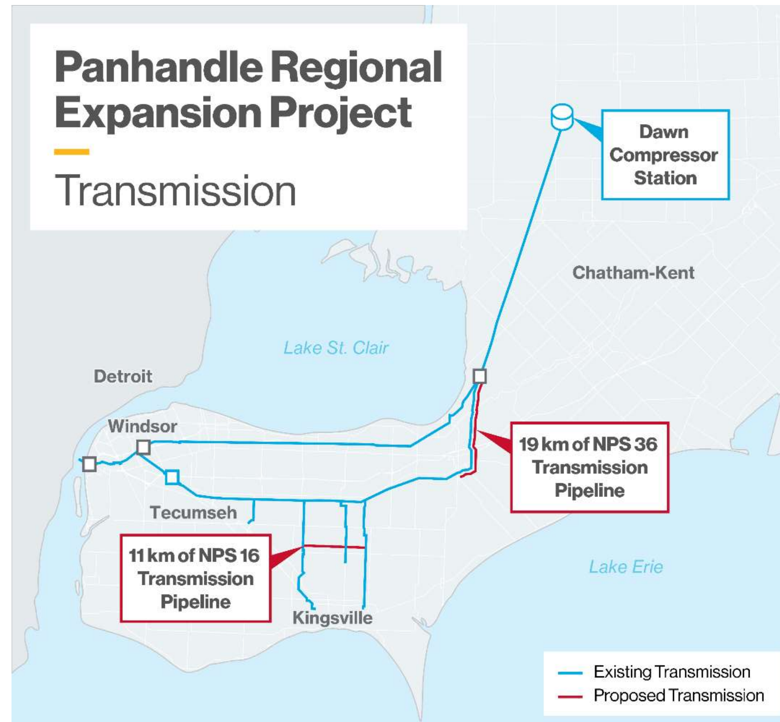
Purpose: Requesting Capital Allocation Committee for approval to proceed to the IRC (Stage 3)

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	• Core business growth project • Most rapidly expanding transmission system
Commercial	High	• Regulated cost of service project • LTC application in abeyance • Seeking cost recovery for incremental CAPEX at earliest opportunity
Financial	High	• Base case DCFROE 8.1%
Ability to Execute	High	• 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	• 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

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	100699	2023	10
	Investment Name		
	Dawn Parkway Expansion Project (Dawn-Enniskillen NPS 48)		

Investment Description

Issue/Concern: In response to increased natural gas demand growth along the Dawn Parkway System, the Kirkwall to Hamilton Expansion has a forecast in-service date of 2029 to 2030 and will provide reliable, secure, economic natural gas capacity to meet the growing design day demand of the Dawn Parkway Transmission system which serves both in- and ex-franchise markets.

Assets: Install approximately 17.2 km of NPS 48 internally-coated pipeline from Dawn Compressor Station (10G-301) to Enniskillen Valve Site (11H-301V) on the Dawn Parkway System.

Related Programs: These facilities are incremental to the Kirkwall to Hamilton Expansion (#48654) and timing is dependent on the Dawn Parkway System demands.

Recommended Alternative Description

Scope of Work: Install approximately 17.2 km of NPS 48 internally-coated pipeline from Dawn Compressor Station (10G-301) to Enniskillen Valve Site (11H-301V) on the Dawn Parkway System.

Resources: Projects group to provide project management support from design and planning phase to project execution.

Solution Impact: Capacity is available on the Dawn Parkway System to meet in-franchise growth and customer demand.

Project Timing & Execution Risks:
-Schedule delays due to right-of-way access for survey, ladn aquisition, environmental studies, permitting, and/or issuance of OEB Leave to Construct may put at risk the planned in-service date.
-Further analysis for potential IRPAs.
-This project will follow Kirkwall to Hamilton (48654). It will be based upon studies done by the Transmission System Planning identifying a need for expansion based upon the demands from the study.
-Estimate/ Forecast does not include MOP Upgrade or Dawn Station Work.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Long Term Planning		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_04 - London
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Spend Profile

Name	Net Base Capex O (CA)
Dawn Parkway Expansion Project (Dawn-Enniskillen NPS 48)	$ 246,634,252

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ -	$ -	$ -	$ 24,612,151	$ 49,222,260	$ 148,187,690	$ 24,612,151	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE

Investment Summary Report

Investment Code	Report Start Year	Number of Years
48654	2023	10

Investment Name

Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48)

Investment Description

Issue/Concern: In response to increased natural gas demand growth along the Dawn Parkway System, the Kirkwall to Hamilton Expansion has a forecast in-service date of November 1, 2026 and will provide reliable, secure, economic natural gas capacity to meet the growing design day demand of the Dawn Parkway Transmission system which serves both in- and ex-franchise markets.

Assets: The Kirkwall-Hamilton Expansion Project consists of 10.2 km of NPS 48 pipeline from the Kirkwall Valve Site to the Hamilton Valve Site.

Related Programs: N/A

Recommended Alternative Description

Scope of Work: System installation of approximately 10.2 km of NPS 48 internally-coated pipeline from Kirkwall Valve Site (17V-302) to Hamilton Valve Site (18W-601V) on the Dawn Parkway System.

Resources: Projects group to provide project management support from design and planning phase to project execution.

Solution Impact: Capacity is available on the Dawn Parkway System to meet in-franchise growth and customer demand.

Project Timing & Execution Risks: In March 2021, this project was pushed out to 2025 and is forecast for November 1, 2026 in-service date. This project was filed with the Ontario Energy Board (OEB); but due to the global pandemic, there was demand uncertainty and the project ultimately was paused. Further analysis for potential IRPAs. Schedule delays due to right-of-way access for survey, environmental studies, land acquisition. permitting, and/or issuance of OEB Leave to Construct may put at risk the planned in-service date.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_16 - Hamilton
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Spend Profile

Name	Net Base Capex O (CA)
Dawn Parkway Expansion Project (Kirkwall-Hamilton NPS 48)	$ 192,008,405

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ -	$ 19,000,000	$ 38,247,415	$ 115,027,169	$ 16,000,000	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	49758	2023	10
	Investment Name		
	Panhandle Regional Expansion Project		

Investment Description

Issue/Concern:
To provide reliable, secure, and affordable natural gas supply to meet the growth in Design Day demand of the Panhandle System:

Assets:
i. Dawn Yard: 700 m of 8960 kPa MOP NPS42 station header is required to maintain the maximum sustainable pressure on design day. This header will also provide operational flexibility and security of supply to the Panhandle system.
ii. Panhandle Take-off Station: The existing station will be modified to meet the new system capacity demand requiring measurement, odourization and regulation assets.
iii. Dover Transmission Station: This existing regulating station will be modified to connect the new NPS 36 pipeline to the upstream system. Flow measurement equipment will also be added to the station.
iv. Panhandle Loop : 19 km of NPS 36 6040 kPag MOP pipeline will parallel the NPS 20 from Dover Transmission station to a new valve site at Richardson Sideroad.
v. Richardson Sideroad Valve Site: A new valve site is required at the end of the NPS 36 Panhandle loop to connect to the existing NPS20 mainline. Isolation valves and launcher/receiver facilities will be installed at this location.

Related Programs: Other PREP Investments: #735972 & 736923

Recommended Alternative Description

1. Scope: To provide reliable, secure, and affordable natural gas supply to meet the growth in Design Day demand of the Panhandle System:

i. Dawn Yard: 700 m ofNPS 42 8960 kPa MOP station header is required to maintain the maximum sustainable pressure on design day. This header will also provide operational flexibility and security of supply to the Panhandle system.
ii. Panhandle Take-off Station: The existing station will be modified to meet the new system capacity demand requiring measurement, odourization and regulation assets.
iii. Dover Transmission Station: This existing regulating station will be modified to connect the new NPS 36 pipeline to the upstream system. Flow measurement equipment will also be added to the station.
iv. Panhandle Loop : 19 km of 6040 kPag MOP NPS36 pipeline will parallel the NPS 20 from Dover Transmission station to a new valve site at Richardson Sideroad.
v. Richardson Sideroad Valve Site: A new valve site is required at the end of the NPS 36 Panhandle loop to connect to the existing NPS20 mainline. Isolation valves and launcher/receiver facilities will be installed at this location.

2. Resources:
This project will be internally managed by EGI staff. Construction work, such as well drilling and new pool piping installation, will be performed by contractors.

3. Solution Impact:
Expansion of the Panhandle system provides customers with increased access to diversity, reliability and security of supply of the Dawn Hub.

4. Project Timing & Execution Risks:
This project starts 2021 with its feasibility endorsed in Q2 2022. Construction will commence in 2023 . The expected in-service date is Fall 2023.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_02 - Chatham
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Spend Profile

Name	Net Base Capex O (CA)
Panhandle Regional Expansion Project	$ 197,451,236

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 167,263,803	$ 8,592,570	$ 67,613	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	736923	2023	10
	Investment Name		
	Panhandle Regional Expansion Project - Leamington Interconnect		

Investment Description

Issue/Concern/Opportunity:
To provide reliable, secure, and affordable natural gas supply to meet the growth in Design Day demand of the Panhandle System,

Assets:

i) Leamington Interconnect : 12 km of 6040 kPag MOP NPS16 pipeline connecting the Leamington North Line, Leamington North Loop, Mersea Line and Kingsville East Line.

ii. Leamington Interconnect Valve Sites: Three new valve sites with isolation valves are required to connect to each of the existing laterals (1. Leamington North Line and Leamington North Loop, 2. Mersea Line and 3. Kingsville East Line). Launcher/receiver facilities will be installed at location 1 and 3.

Related Program: Not Applicable

Recommended Alternative Description

1. Scope Install approximately 11 km of NPS 16 connecting Kingsville East Line, Mersea Line and the Leamington North Lines.

Reinforcement projects broadly involve the installation of new or modification of existing gas distribution assets to maintain minimum required system pressure, maintain capacity, and meet customer demand. These projects are primarily driven by customer growth and system reliability considerations. Failure to implement reinforcement projects in a timely manner could lead to a potential inability to support increasing demands of existing customers and the addition of future customers.

2. Resources:
This project will be internally managed by EGI staff. Construction work, such as well drilling and new pool piping installation, will be performed by contractors.

3. Solution Impact:
Expansion of the Panhandle system provides customers in the Leamington and Kingsville area with increased access to diversity, reliability and security of supply of the Dawn Hub.

4. Project Timing & Execution Risks:
This project starts 2021 with its feasibility endorsed in Q2 2022. Construction will commence in 2024 . The expected in-service date is Fall 2024.

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Growth
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_01 - Windsor
	Asset Program (EGI)	TPS - Growth
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	Yes
	Intolerable Risk (EGI)	No
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Spend Profile

Name	Net Base Capex O (CA)
Panhandle Regional Expansion Project - Leamington Interconnect	$ 55,278,330

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 12,242,784	$ 39,598,802	$ 3,047,378	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 6/2/2022

ENBRIDGE Investment Summary Report	Investment Code	Report Start Year	Number of Years
	100086	2023	10
	Investment Name		
	Panhandle Line Replacement		

Investment Description

Issue/Concern:
Enbridge Gas Inc.'s (EGI's) Integrity Management team initiated work in 2019 to better understand the risk associated with the two NPS12 crossings that connect the Panhandle Eastern System owned and operated by Energy Transfer in Michigan with the EGI system in Ontario. These two crossings, installed in 1947, have never been internally inspected to check for the presence of the primary threat of internal corrosion; such inspection cannot be achieved given the configuration of the asset. A risk assessment was recently completed for the river crossings. The risk owner and risk approver reviewed the risk results and have decided the risk requires treatment with a permanent solution.

Assets: Transmission Pipeline (Canada Energy Regulator-regulated crossing)

Related Programs: N/A

Recommended Alternative Description

Scope of Work: Replacement of the twin NPS 12 Crossings with a single pipeline of equivalent capacity.

Resources: Projects group to provide project management support from design and planning phase to project execution.

Solution Impact: The principal risk is the lack of In-line Inspection (ILI) data needed to inform effective decision-making to mitigate a potential loss of pipeline containment (i.e., leak). Replacement with a new single pipeline, designed, manufactured and constructed to current standards that is ILI-capable can address this risk.

Project Timing & Execution Risks: Original in-service date is estimated to be Q3 2024. Overall project schedule is highly dependent on regulatory process and discussion with joint partner (Energy Transfer).

Investment Type	Project (EGI)	Planning Portfolio	UG - Core - Transmission Pipe & Underground Storage - Replacements
Investment Stage	Executing		

Investment Overview

1. Project Information	State/Province	Ontario
	Operating Area (EGI)	Div_01 - Windsor
	Asset Program (EGI)	TPS - Replacements
	Asset Class (EGI)	Transmission Pipe & Underground Storage
2. Compliance	Compliance Investment	No
	Compliance Justification & Code	
3. Must Do	Must Do Investment	No
	Intolerable Risk (EGI)	Yes
	Third Party Relocation (EGI)	No
	Program work with sufficient history and risk to warrant continuation (EGI)	No

Spend Profile

Name	Net Base Capex O (CA)
Panhandle Line Replacement	$ 29,809,389

Account Type	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base CAPEX O	$ 1,619,900	$ 24,257,660	$ 3,392,719	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dismantlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Report Generation Date: 5/30/2022

Residential: Single Family Natural Gas End Use Study

2021 Annual Results

ENBRIDGE
Life Takes Energy

Customer & Market Insights

Objectives

- To measure the penetration of natural gas appliances in the single family residential customer market;
- To understand customer perceptions of the levels of insulation in their home;
- To determine awareness of Enbridge Gas' energy conservation programs, and understand where customers turn to for more information.

Methodology

- Sponsor-identified telephone interviews were completed by Leger between November 23 and December 17, 2021.
- Interviews were completed with customers who reside in single family dwellings and are (mainly) responsible for making energy-related decisions for the home.
- The total number of completed interviews is 2,404 with 1,200 for each of LUG and LEG in total, and final franchise-wide results are calculated based on true geographic proportions.
- Overall results yield a margin of error of +/-2.8% at the 95% confidence interval.
- Unless otherwise noted, results in this report are based on all customers (EGI, comprised of LUG and LEG combined).
- The regions reported in this report are defined as follows:

Region Name	Includes	
Northern	Northeast, Northwest	LUG
LUG Eastern	Eastern	LUG
LEG Eastern	DMA 65	LEG
GTA West & Niagara	DMA 76, DMA 53, DMA 21	LEG
Toronto	DMA 01	LEG
GTA East	DMA 35, DMA 45, DMA 47	LEG
Southeast	Waterloo/Brantford, Hamilton/Halton	LUG
Southwest	Windsor/Chatham, Sarnia/London	LUG

Executive Summary (1 of 2)

Natural Gas Penetration

- There was a statistically significant decrease in the penetration of natural gas heating and natural gas water heating in 2021 compared to the previous year. These trends should be monitored.
- When asked to think about a new home, barring any other considerations, most customers continue to choose natural gas, though a small, but growing, proportion would choose alternate sources, such as geothermal or solar for home and water heating, respectively.
- The prevalence of natural gas in secondary appliances is consistent over the last few years for cooktop/stove and clothes dryers. Fireplace and barbecue show signs of decrease. Across secondary appliances, some regional variation continues to exist.

Ownership

- Furnace ownership continues to be very high (84%), though an increasing trend in renting is observed. Renting is a bit more common among newer homes and among younger customers. Overall, in the case of future ownership, most customers intend to own (79%), but this is significantly lower compared to 2020 (92%).
- Ownership of water heaters remains steady over the last several years for LUG customers and is similar among LEG customers. It continues to remain much lower than furnace ownership. Among those who are at least fairly likely to replace their water heater in the next 2 years, interest in ownership is much stronger (69%) than current ownership (43%).

Furnace Efficiency

- A different approach to asking customers about the efficiency level of their furnace was introduced in 2020. A higher proportion of customers continue to report that their furnace is high-efficiency.
- A sizable group of customers do not know the efficiency level of their furnace (this has not changed much over the past decade) – customers who don't know are not likely to be aware of and act on the potential for upgrades.
- There is a continued increase in the proportion of customers who have a Smart Thermostat (27%), up from 23%, as customers upgrade their thermostats; about 2-in-3 customers with a programmable or Smart thermostat actively program it to reduce energy consumption.

Executive Summary (2 of 2)

Insulation

- About 2-in-5 customers (43%) deem their house to be "well insulated" while 7% indicate it is "poorly insulated" or "not insulated," which varies by the age of the home. A sizeable proportion of customers (14%) don't know the level of insulation for their home, but most are able to communicate the level of draftiness they experience in their home.
- About 1-in3 customers whose home is not "well insulated" would improve insulation to "save money on utility bills", while 26% would do so to increased comfort. Another 22% of customers would not bother improving their insulation.

Energy Efficiency (EE) and DSM offerings

- The proportion of customers planning to make energy efficiency updates returned to the 2019 level (26%) at the end of 2021 (18% in 2020 and 25% in 2019).
- Awareness that Enbridge Gas offers energy conservation programs sits at 64% among LUG customers and at 52% among LEG customers – this varies by customer age group and region.
- Overall, customer awareness of the HWP and HER programs remains strong at 21% and 31%, respectively. Among all customers, 29% are aware of the rebates and discounts on a Smart Thermostat. Among those aware of the respective programs, 16% have participated in HWP, 25% in HER and 20% in Smart Thermostat.
- Though decreasing over time, the internet continues to be the most important source of general energy efficiency information – highlighting the importance of digital marketing and strong website content. "Direct from Enbridge Gas" accounts for 10% of the mentions as an energy efficiency information source.

Overview of Natural Gas (NG) Equipment

- Comparing 2021 to 2020, the penetration of natural gas is down directionally for home heating, water heaters, indoor fireplaces and barbecues. The penetration of natural gas clothes dryers and cooktops/stoves remains unchanged.
- Natural gas for home heating is just slightly higher in LUG compared to LEG, and the use of natural gas for clothes dryers continues to be significantly higher in LUG.

Natural Gas Penetration Rates across Appliances

	2014	2015	2016	2017	2018	2019	2020			2021		
			LUG			EGI	EGI	LUG	LEG	EGI	LUG	LEG
Home Heating	96%	96%	95%	96%	94%	96%	96%	96%	97%	94%	95%*	93%
Water Heater	85%	86%	86%	83%	82%	82%	85%	83%	86%	80%	79%	81%
Fireplace	38%	41%	44%	36%	42%	35%	42%	43%	42%	37%	38%	36%
Cooktop/Stove	29%	26%	31%	29%	31%	30%	31%	30%	32%	32%	32%	32%
Barbecue	27%	23%	26%	20%	24%	24%	27%	28%	25%	23%	25%	23%
Clothes Dryer	21%	20%	19%	17%	19%	16%	15%	17%*	13%	14%	17%*	10%
Pool Heater	(--)	(--)	(--)	(--)	5%	6%		(--)		5%	3%	3%

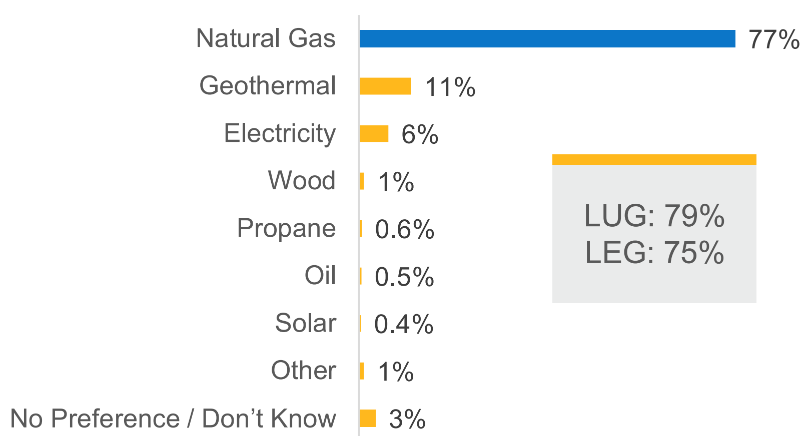
(--) = was not measured

* Indicates result is significantly higher at a 95% confidence level for this customer group compared to the other (comparing LUG and LEG customers) or against the total.

Home Heating: Preference

- Most customers (77%) would prefer natural gas for home heating in a new home (down from 83% in 2020 and 86% in 2019).
- Preference for geothermal (11%) and electricity (6%) in new homes continues to trend upward.
- Preference for natural gas is strongest in the Northern (82%) region, while lowest in the Toronto (66%) region.
- Key reasons for choosing an alternate fuel source include the perception that it is more environmentally friendly / energy efficient (especially for geothermal) and has lower operation costs. Also, electricity is deemed to be safer by some customers.

Preferred Fuel Source for Home Heating
(Base: all customers, n=2,404)



Reason for Preferred Fuel Source
(Base: all customers who indicated a preferred fuel source)

	Natural Gas (n=1,841)	Electricity (n=143)	Geothermal (n=254)
Lower operation cost	54%	18%	33%
Environmentally friendly / Energy efficient	21%	37%	70%
It is what I am used to / Used in the past	16%	7%	2%
Easier / More convenient	14%	8%	1%
Reliable / Dependable heat source/ Best option	11%	8%	7%
It is what is available/ Preferred source not available	8%	4%	1%
More heat generated / It's warmer	3%	1%	0.4%
Safer / Safety concerns	2%	13%	1%
Other	3%	8%	8%
DK/NA/Refused	4%	11%	2%

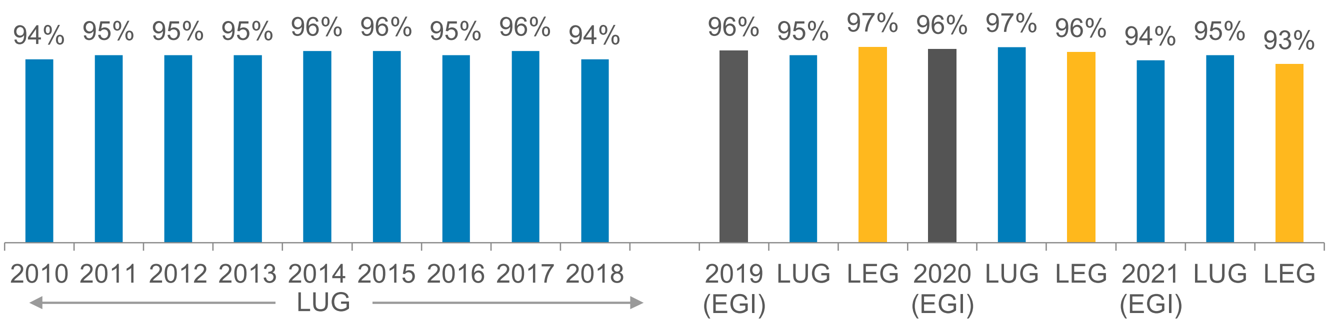
Q: I would now like you to assume that you are moving into a new home. Which energy source would you choose for each of the following? PRIMARY home heating Q: What would you say are your main reasons for choosing (insert choice) as your primary source for your home heating? (Total mentions)

Residential: Single Family Natural Gas End Use Study

Home Heating: NG Adoption & Equipment

- Natural gas forced air furnaces continue to be the most used heating equipment across the franchise.
- A sizable portion of customers are not aware of the specific type of heating equipment they have in their home (1-in-10 among those who heat with natural gas)
- Those who don't use natural gas for home heating use electricity (5%) followed by only handfuls in the sample of customers who heat with wood, propane, or oil.

Natural Gas Penetration: Home Heating
(Base: all customers)



Q: What is the MAIN energy source for heating your home? Q: What type of **(PROPANE/NATURAL GAS/OIL)** furnace or heating system do you have? Q: What type of electric system are you using to heat your home?

Type of Natural Gas Heating Equipment (n=2,236)	
Forced Air	78%
Hydronic	4%
Space Heaters	0%
Combination	2%
Hybrid or dual-fuel system of a forced air furnace and electric air source heat pump	3%
Don't Know	13%

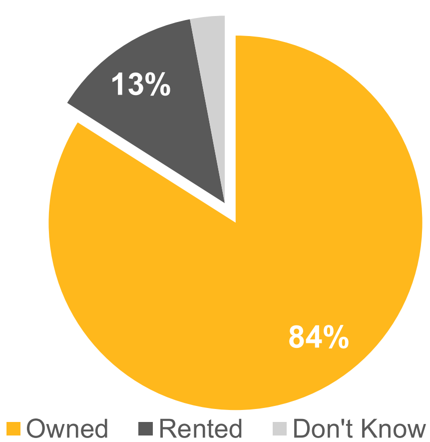
Type of Electric Heating Equipment (n=111)	
Forced Air	62%
Baseboard Heaters	14%
Air Source Heat Pumps	1%
A hybrid or dual-fuel system of a forced air furnace and electric air source heat pump	5%
Electric boiler (radiator)	2%
Other	5%
Don't Know	13%

Home Heating: Furnace Ownership

- Most customers own their furnace (or heating system), and most customers who anticipate replacing their furnace or heating system in the future would continue to own it (rather than rent it). Furnace ownership is down considerably compared to 2020 (from 89% for 84%) and future ownership intention (from 92% to 79%).
- Rental rates are higher among some customer groups, including households that also rent the water heater (16%), in homes built since 2000 (16%), those with incomes under $40K (19%) and among younger (18-34) customers (18%).

Ownership of Current Furnace / Heating System

(Base: customers who use electricity, natural gas or oil for home heating, n=2,354)

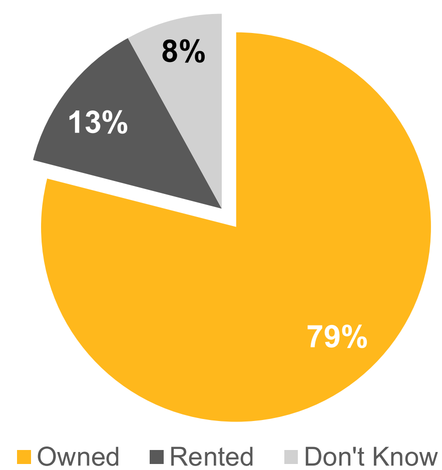


Region	Owns (%)
Northern	88%
LUG Eastern	93%
LEG Eastern	84%
GTA West & Niagara	78%
Toronto	85%
GTA East	79%
Southeast	86%
Southwest	87%

Among younger customers (age 18-34) ownership level is lower at 76% compared to their counterparts, especially those age 65+ (90%)

Ownership of Replacement Furnace / Heating System

(Base: customers who are at least fairly likely to replace their furnace n=301)



Q: Is your furnace or heating system owned or rented? Q: Is your replacement furnace or heating system most likely to be owned or rented?

* Indicates result is significantly higher at a 95% confidence level for this customer group compared to the other (comparing LUG and LEG customers) or against the total.

Residential: Single Family Natural Gas End Use Study

- Most forced air furnaces are less than 10 years old (71%) with 2-in-5 of those whose furnace is less than 5 years old indicating that they replaced it in the last 2 years, with about half of those also replacing their air conditioner at the same time.
- The Northern and Southwest region has a larger proportion of older furnaces, specifically those aged 16-20 years (10%) compared to the average (6%).
- When asked about furnace efficiency most indicated that their furnace is high efficiency, and with a change in the question last year (using the age of furnace as a starting point) this proportion is higher than in previous years and should be interpreted with caution.

Age of Forced Air Furnace (all fuels)	
5 years or less	41%
6 to 10 years	30%
11 to 20 years	20%
More than 20 years	5%
Don't Know	5%

38% of those who currently have a furnace that is less than 5 years old have replaced it in the last 2 years (or 13% of the total)

50% of customers who replaced their furnace in the past 2 years and also had an air conditioner also replaced it at the same time

Fuel Source for Original (replaced) Furnace	
Natural Gas	87%
Electricity	4%
Oil	5%
Other	1%
Don't Know	3%

90% of customers whose furnace is less than 10 years old indicate that their furnace is high-efficiency

68% of customers whose furnace is more than 10 years old indicate that their furnace is high-efficiency, among the remainder, 10% indicate having a mid-efficiency furnace and 10% a conventional furnace (9% indicate "don't know")

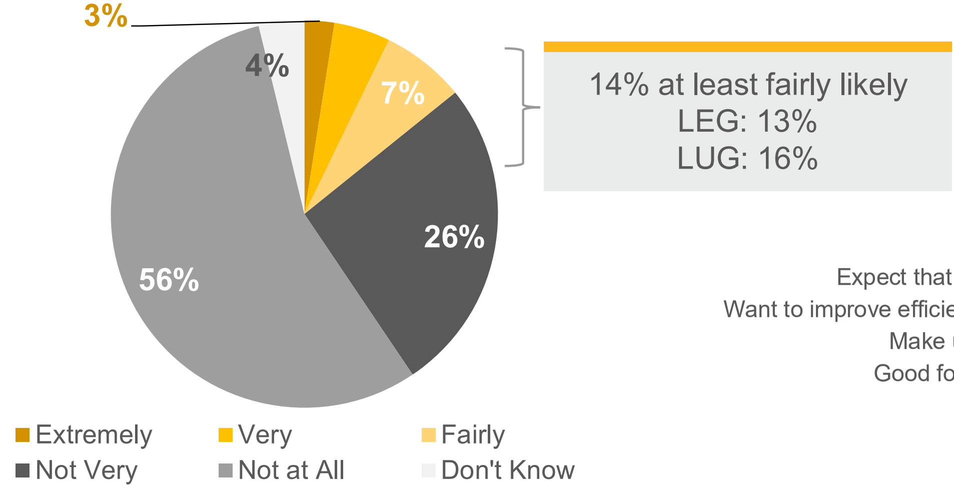
Forced Air Furnace Efficiency (natural gas)*	
High efficiency (over 90% efficiency)	81%
Medium efficiency	3%
Conventional (less than 75%)	3%
Don't Know	14%

Q:How old is your furnace? Q: Is this a high-efficiency furnace? IF NEEDED: it would likely have one or two plastic vent pipes (often white) that vent out a side wall. Q: What would you say the efficiency level of your furnace is? Would it be a high-efficiency furnace that vents through the side of the house, like dryer, but with a smaller plastic pipe? Q: Is it a furnace with a metal chimney coming up through the roof, such as a conventional furnace (which has a continuously lit pilot light) or a mid-efficiency furnace (which does not have a pilot light)?

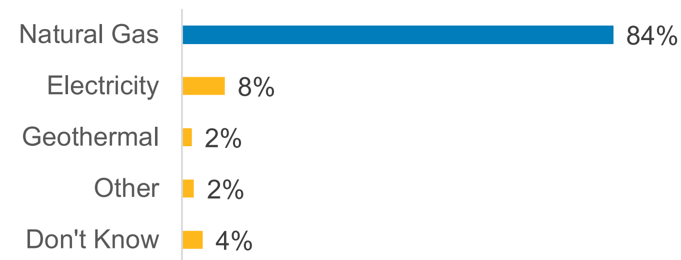
Home Heating: Furnace Replacement

- A small proportion of customers (14%) indicate that they are at least likely to replace their furnace in the next 2 year because it is likely to break down – among them most would get a natural gas furnace.
- Making use of current rebates/program increased by 2% over 2020.
- Of those likely to switch home heating source from natural gas cited "environmental impact" as the main factor.

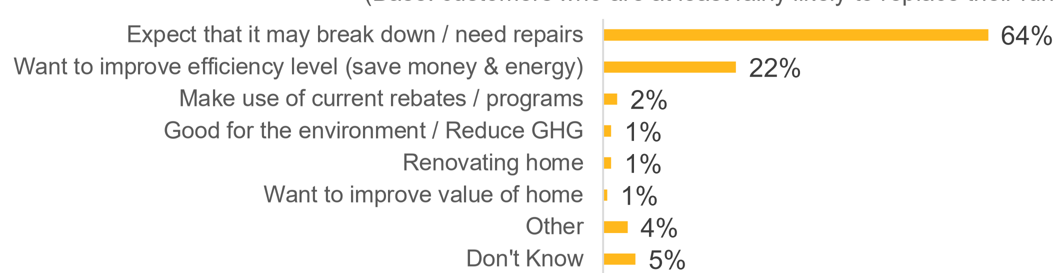
Likely to Replace Furnace in Next 2 Years
(Base: customers who have not replaced their furnace in the past 2 years, n=2,108)



Fuel Source of New Furnace
(Base: customers who are at least fairly likely to replace their furnace n=301)



Reason For Replacing Furnace
(Base: customers who are at least fairly likely to replace their furnace n=301)



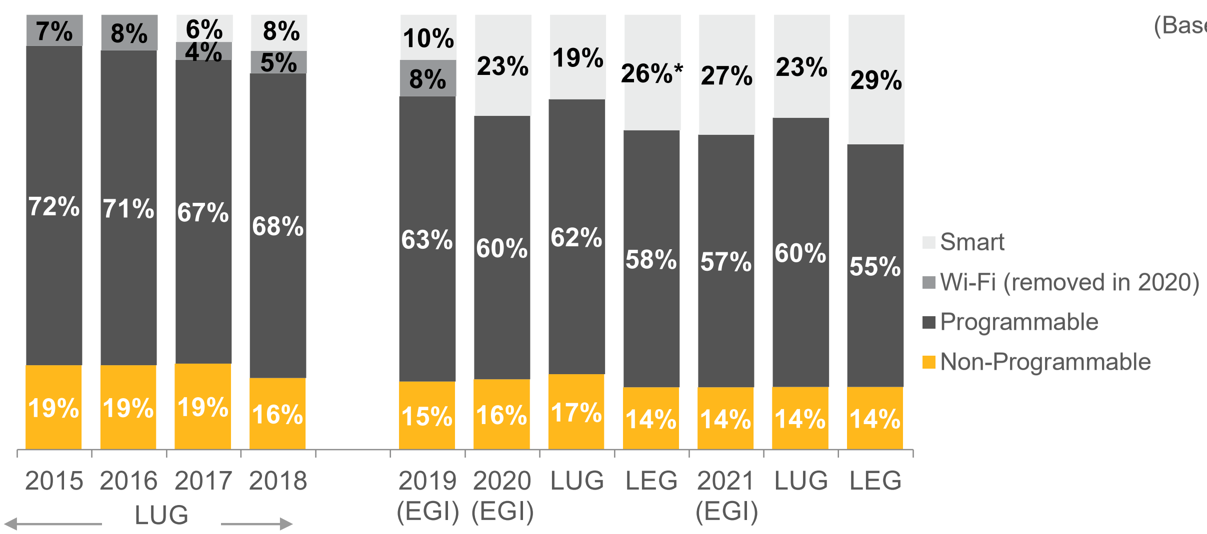
Q:How likely are you to replace the furnace or home heating system in the next 2 years? Q: Which energy source will the new furnace or heating system use? Q: What would you say is the main reason that you are fairly/very/extremely likely to replace your furnace or home heating system?

Home Heating: Thermostats

- Smart thermostats continue to gain in popularity. They are most popular in the GTA East area (36%; up from 30% in 2020), in newer homes (37%), and among higher earning households (42%), and younger customers (40%).
- Non-programmable thermostats appear disproportionately among customers in the Northern (22%) and Toronto (20%) regions, and in older (17%), smaller (18%), lower income (26%), and senior (18%) occupied homes. Opportunities to upgrade thermostats continue to exist, as well as opportunities to encourage customers to actively program their thermostats.

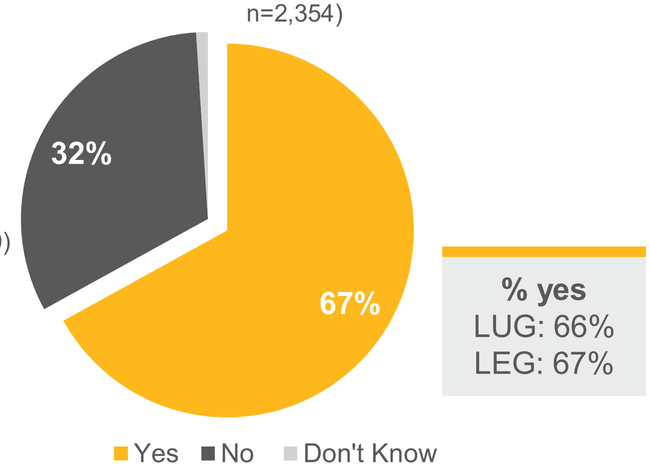
Type of Thermostat

(Base: all customers, n=2,404)



Actively program thermostat to help reduce energy use

(Base: all customers with Smart or Programmable thermostat, n=2,354)



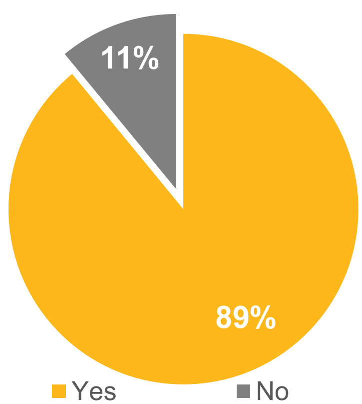
Q: Which of the following thermostats do you have? Q: Do you actively program your thermostat to help reduce your energy use? Response options changed in 2017, and again changed in 2020.

* Indicates result is significantly higher at a 95% confidence level for this customer group compared to the other (comparing LUG and LEG customers) or against the total.

Air Conditioning

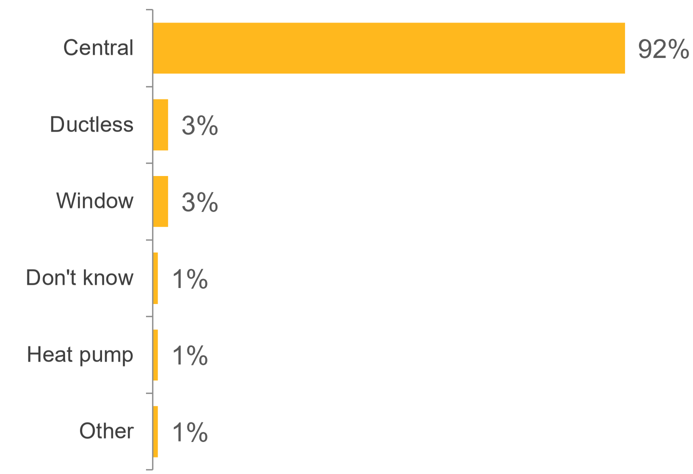
- There is considerable variation across the franchise ranging from 92% among LEG customers to 85% among LUG customers, and from 69% in the Northern region to 93% in the GTA West and LEG Eastern regions in terms of whether a customer has air conditioning or not.
- Air conditioning is also significantly more common in newer houses with 98% of homes built since 2000 having central air conditioning vs. only 75% of homes built before 1950. Proportions are similar by income with air conditioning in 94% of households earning at least $140K vs. 82% of households earning less than $40K.
- Just over half (56%) of customers who replaced their furnace or heating system in the past 2 years also replaced the air conditioner. Homes built between 1990-1999 were significantly more likely to have replaced the air conditioner (73%).

Have Air Conditioning
(Base: all customers, n=2,404)



Region	Yes (%)
Northern	69%
LUG Eastern	80%
LEG Eastern	93%*
GTA West & Niagara	93%*
Toronto	90%
GTA East	92%*
Southeast	92%*
Southwest	89%

Type of Air Conditioning
(Base: customers who have air conditioning, n=2,130)

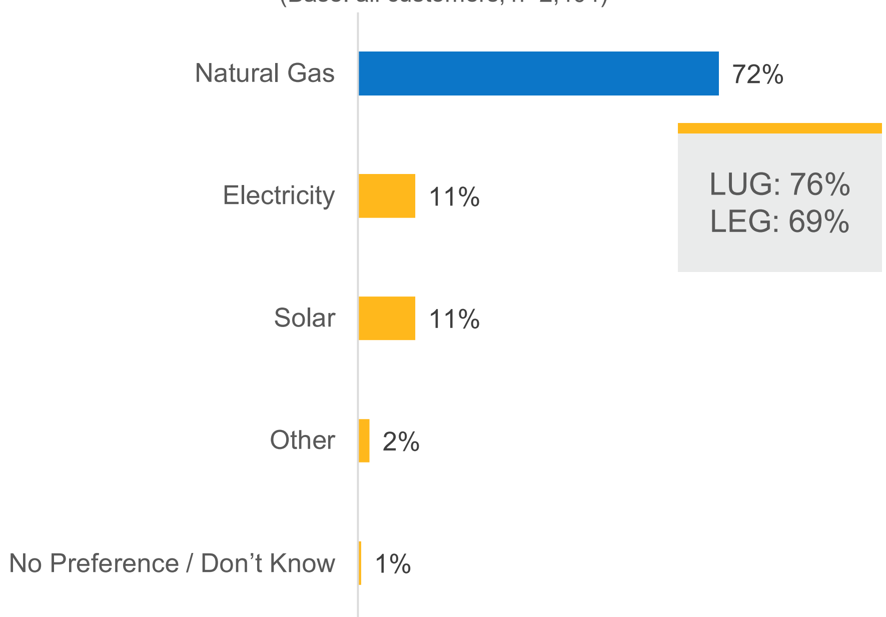


Q: Do you have air conditioning in your home? Q: Which of the following types of air conditioning do you use in your home?
* Indicates result is significantly higher at a 95% confidence level for this customer group compared to the other (comparing LUG and LEG customers) or against the total.

Water Heating: Preference

- Most customers (72%) would prefer natural gas for water heating in a new home (down from 78% in 2020 and 81% in 2019), followed by electricity (11%) and solar (11%). The preference for natural gas is slightly higher among LUG customers, and regionally is highest in the Southwest (80%) and Eastern (76%) regions.

Preferred Fuel Source for Water Heating
(Base: all customers, n=2,404)



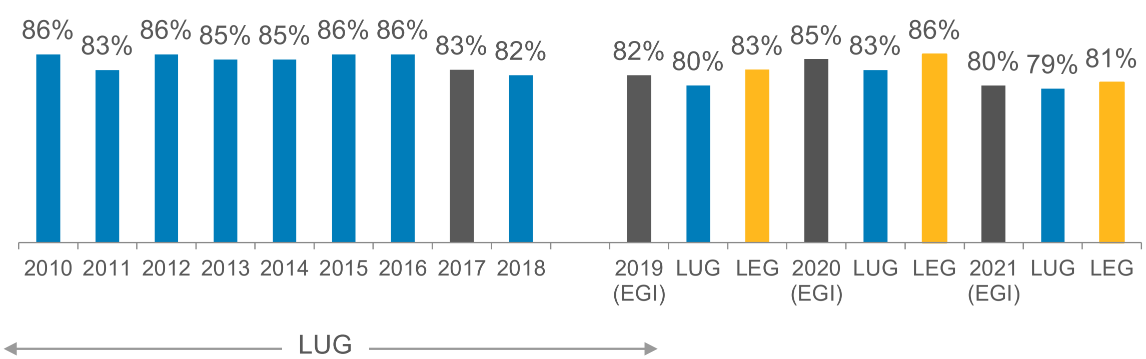
Region	Natural Gas (%)
Northern	74%
LUG Eastern	69%
LEG Eastern	76%
GTA West & Niagara	73%
Toronto	62%
GTA East	71%
Southeast	75%
Southwest	80%*

Q: I would now like you to assume that you are moving into a new home. Which energy source would you choose for each of the following? Water heater?
* Indicates result is significantly higher at a 95% confidence level for this customer group compared to the other (comparing LUG and LEG customers) or against the total.

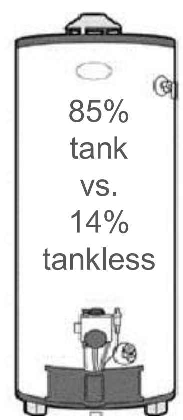
Water Heating: NG Adoption & Equipment

- Penetration of natural gas water heaters has continued to trend downward over the past few years. Natural gas use for water heating ranges from 76% in the Eastern and Northern regions to 83% in the Southeast and Southwest regions.
- The proportion of tankless water heaters continues to grow slowly up from 6% in 2017 to 14% in 2021. Tankless water heaters are more prevalent in homes built after 2000 with 2,500+ square feet.

Natural Gas Penetration: Water Heating
(Base: all customers)



Q: What type of water heater do you have? Is it...? Q: How old is your water heater? Q: Does your water heater have a tank or is it tankless? IF NEEDED READ *Tankless water heaters are also called continuous or instantaneous water heaters.*



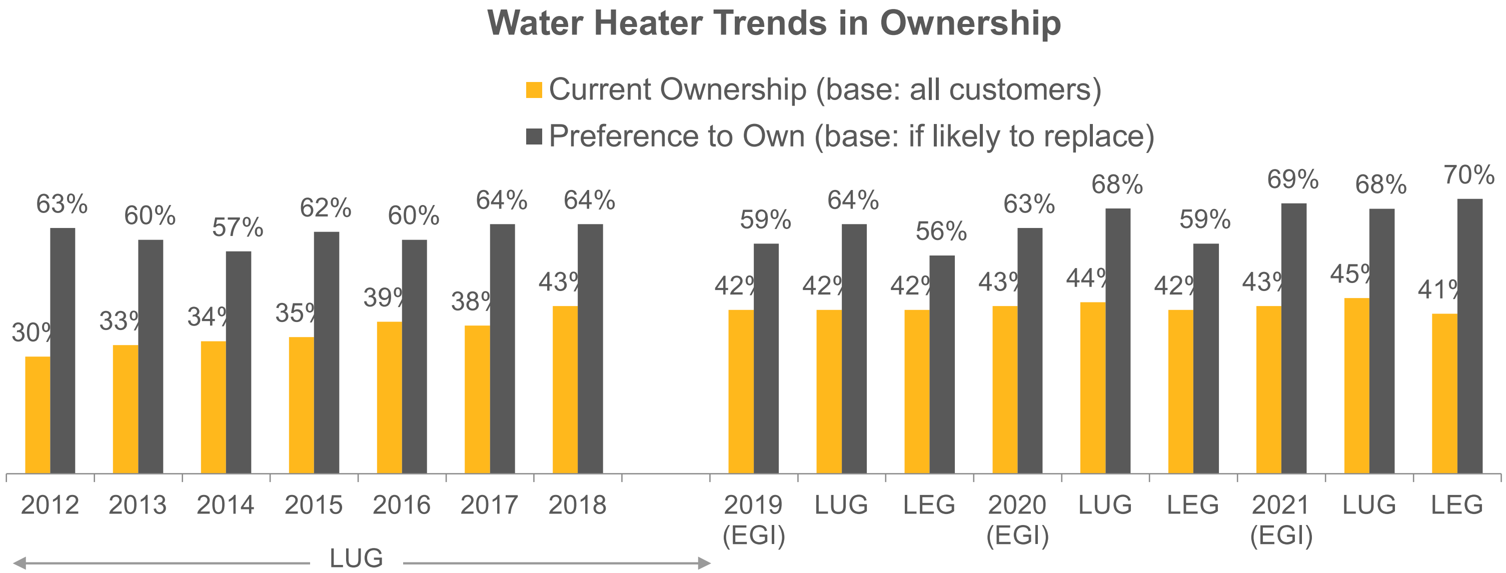
Age of Water Heater (all)	
5 years or less	48%
6 to 10 years	30%
11 to 15 years	10%
More than 15 years	5%
Don't Know	7%

Region	Tankless (%)
Northern	18%
LUG Eastern	12%
LEG Eastern	12%
GTA West & Niagara	16%
Toronto	16%
GTA East	14%
Southeast	10%
Southwest	14%

Residential: Single Family Natural Gas End Use Study

Water Heating: Ownership

- Current ownership is the same among LUG and LEG customers and is quite consistent for LUG over the last couple of years.
- Ownership tends be higher among customers who have an electric water heater compared to one that is fueled by natural gas.
- Future intentions continue to lean toward ownership – 70% plan to own, (69% among LUG customers and 70% among LEG customers).



Owned % by type of water heater
Natural Gas: 40%
Electricity: 56%

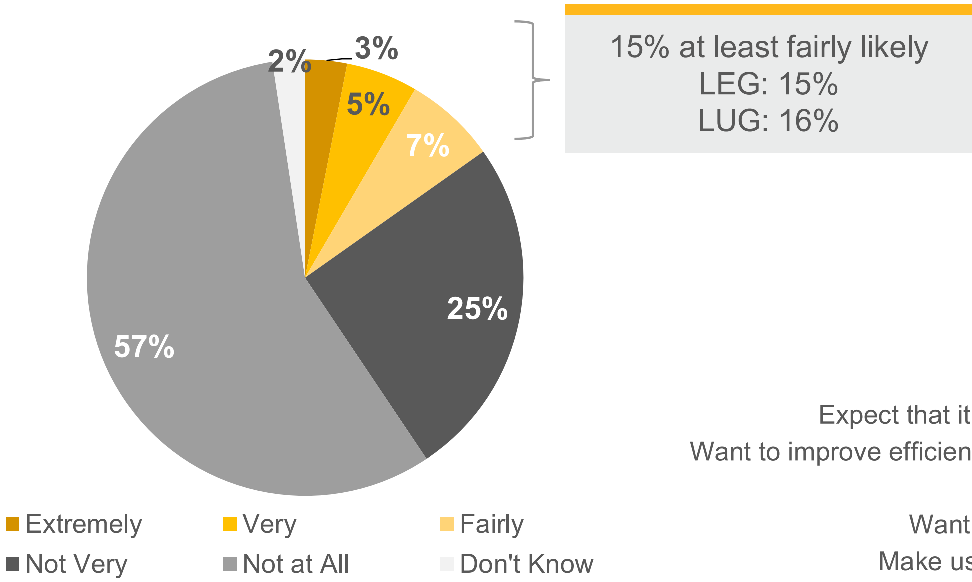
Q: Is your water heater owned or rented? Q: Is your replacement water heater most likely to be owned or rented?

Water Heating: Replacement

- Similar to furnaces, a small proportion of customers (15%) indicate that they are at least likely to replace their water heater in the next 2 years because it is likely to break down or because they're looking to improve the efficiency level – among them, most would get a natural gas water heater.
  - Customers' desire to improve the efficiency level of the water heater increase 10 points compared to 2020 (17% vs. 27%)

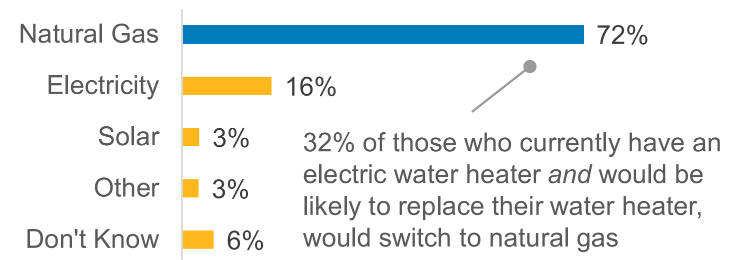
Likely to Replace Water Heater in Next 2 Years

(Base: customers who have a water heater and own their home n=2,079)



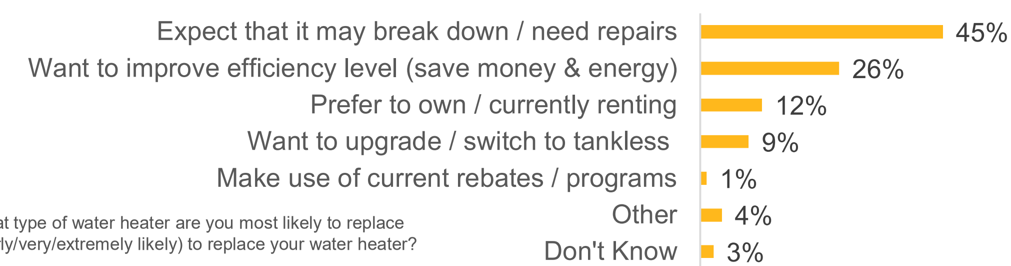
Fuel Source of New Water Heater

(Base: customers who are at least fairly likely to replace their water heater n=319)



Reason For Replacing Water Heater

(Base: customers who are at least fairly likely to replace their water heater n=319)



Q: How likely are you to replace your water heater in the next 2 years? Are you...? Q: What type of water heater are you most likely to replace your current water heater with? Q: What would you say is the main reason that you are (fairly/very/extremely likely) to replace your water heater?

Enbridge Contract Customer Demand Assumption Per EB-2022-0157 Exhibit I.STAFF.24
Example Calculation for CIAC

Table 1: 2024 and 2025 Incremental Customer Demand Requirements (Underpinned by Firm Distribution Contract and In Negotiation) by Customer and Sector

Status	Customer	Sector	TJ/Day				
			2024	2025	Total	% of Demand	CIAC $ millions
Underpinned by Firm Distribution Contract							
	1	Power	57.4	0	57.4	43.75	148.8
Total Underpinned by Firm Distribution Contract			**57.4**	**0**	**57.4**		
In Negotiation							
	2	Power	0	6.3	6.3	4.8	16.33
	3	Power	0	25.1	25.1	19.13	65.06
	4	Greenhouse	0.5	3.1	3.6	2.74	9.33
	5	Greenhouse	2.4	0	2.4	1.83	6.22
	6	Greenhouse	0	2.4	2.4	1.83	6.22
	7	Greenhouse	2.2	0	2.2	1.68	5.70
	8	Greenhouse	0	2.1	2.1	1.6	5.44
	9	Greenhouse	1.6	0	1.6	1.22	4.15
	10	Greenhouse	0	1.4	1.4	1.07	3.63
	11	Greenhouse	1.3	1.6	2.9	2.21	7.52
	12	Greenhouse	1.3	1.3	2.7	2.06	7.00
	13	Greenhouse	0	1	1	0.76	2.59
	14	Greenhouse	0	0.9	0.9	0.69	2.33
	15	Greenhouse	0.4	0	0.4	0.30	1.04
	16	Greenhouse	0.2	0	0.2	0.15	0.52
	17	Greenhouse	0	4.5	4.5	3.43	11.67
	18	Greenhouse	0	3.1	3.1	2.36	8.04
	19	Greenhouse	0	2.2	2.2	1.68	5.70
	20	Greenhouse	0	1.6	1.6	1.22	4.15
	21	Greenhouse	0	1.3	1.3	0.99	3.37
	22	Food and Beverage	0	0.1	0.1	0.08	0.26
	23	Greenhouse	0	0.9	0.9	0.69	2.33
	24	Greenhouse	0	1.1	1.1	0.84	2.85
	25	Greenhouse	0	1.7	1.7	1.3	4.41
	26	Greenhouse	0	0.8	0.8	0.61	2.07
	27	Greenhouse	0	1.3	1.3	0.99	3.37
Total In Negotiation			**9.9**	**63.8**	**73.8**		
Total Underpinned by Firm Distribution Contract and In Negotiation			**67.3**	**63.8**	**131.2**	**100%**	**340.1**

Note: Total Project Cost = $358 million
= $340.1 million (95% Contract Demand) + $17.9 million (5% non-Contract Demand)

A. Integrated Resource Planning

5. The Decision and Order for Enbridge Gas' Integrated Resource Planning Framework Proposal (EB-2020-0091) was issued on July 22, 2021. This decision was accompanied by an Integrated Resource Planning Framework for Enbridge Gas ("IRP Framework")[1]. The IRP Framework provides guidance from the OEB about the nature, timing, and content of IRP considerations for future identified needs. The IRP Framework provides Binary Screening Criteria in order to focus on situations where there is reasonable expectation that an IRP Alternative ("IRPA") could technically and economically meet a system need. The Binary Screening criteria were applied, and it was determined that the need underpinning the Project does not warrant further IRP consideration based on the timing criteria, as the need must be met in under three years:
   - **Timing:** If a system need must be met in under three years, an IRP Plan could not likely be implemented and its ability to resolve the identified system constraint could not be verified in time. Therefore, an IRP evaluation is not required. Exceptions to this criterion could include consideration of supply-side IRPAs and bridging or market-based alternatives where such IRPAs can address a more imminent need.[2]

6. Notwithstanding that an IRP evaluation was not required due to the timing criteria discussed above, Enbridge Gas evaluated supply-side alternatives both alone and in combination with an Enhanced Targeted Energy Efficiency ("ETEE") IRP alternative to determine if implementation of these alternatives could meet the need within the required timeframe. For the reasons discussed below, the supply-side and ETEE alternatives were unable to meet the growing needs of the Panhandle System from a technical and/or financial feasibility perspective.

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[1] EB-2020-0091, Decision and Order, July 22, 2021, Appendix A
[2] *ibid*, P. 10

Integrated Resource Planning

Regional Webinar

ENBRIDGE
Life Takes Energy

Southwest Region
Thursday, April 6, 2023

SUZANNE:
Thanks to everyone who has joined the call today and we are looking forward to sharing with you information regarding Ontario's energy transition and the exciting new natural gas planning initiative Enbridge Gas is exploring.
My name is Suzanne Shea, Supervisor Community Engagement also on this call presenting today are:
Heidi Steinberg Laxton – Specialist, Energy Transition
Chris Ripley – Manager, Integrated Resource Planning
Kurtis Lubbers – Supervisor – Distribution Optimization Engineering
Whitney Wong – Specialist, Integrated Resource Planning

Land acknowledgment

The land we gather on today has been inhabited by and cared for by people Indigenous to Turtle Island since time immemorial. We recognize and respect the historic connection to and harmonious stewardship by the Indigenous peoples over this shared land and, as such, we have a responsibility to preserve and care for the land, learn from the original inhabitants and move forward together in the spirit of healing, reconciliation and partnership.

2

SUZANNE:
As we have attendees joining from various locations, we offer this land acknowledgment

The land we gather on today has been inhabited and cared for by people Indigenous to Turtle Island since time immemorial. We recognize and respect the historic connection to and harmonious stewardship by the Indigenous peoples over this shared land and, as such, we have a responsibility to preserve and care for the land, learn from the original inhabitants and move forward together in the spirit of healing, reconciliation and partnership.

Enbridge is committed to a path of reconciliation and recently released our first Indigenous Reconciliation Action Plan (also known as IRAP). The IRAP will serve as the roadmap by which we will continue our journey to advance truth and reconciliation.
It is the mechanism by which we will remain accountable for executing on our commitments and to our partners, including Indigenous peoples.

Safety moment

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- 53% of distracted walking incidents involving cell phones happen at home
- 54% are people ages 40 or younger
- Aside from getting injured, distracted walking makes you an easy target for attacks and robberies
- It is as important to walk "cell free" just like how you drive free without holding your phone

3

SUZANNE:
Before we move onto the agenda, it is practice at Enbridge to begin each meeting with a safety moment.

Today's safety moment is about distracted walking.

As you can see on the slide:

53% of distracted walking incidents involving cell phones happen at home.
54% are people ages 40 or younger
Aside from getting injured, distracted walking makes you an easy target for attacks and robberies
It is as important to walk "cell free" as it is driving without holding or looking at your phone

Aside from distracted walking, please keep in mind the following rules of courtesy while walking:

- When walking in groups, try to avoid walking three or four people across and blocking others from moving freely around you on the side walk or blocking the path of on–coming walkers.

- Think of walking as driving and stay to the right. If you need to move around someone, do so and then go back to the right to avoid oncoming pedestrians.

- Just because you can see a car, doesn't mean the driver can see you. Wait before stepping off a curb to make sure you have a clear path of travel.

- Avoid listening to loud music in your headphones so you can hear what is happening around you.

- Warn others who may be distracted of danger in front of them. Shout out or gently grab a person who is about to put themselves in harms way.

I know I see a lot of people looking at cell phones while they are walking so this is a good reminder as we head outdoors to enjoy the nice weather to put your phone away and pay attention to your surroundings.

Agenda

- Engagement process & webinar objectives
- Pathways to Net Zero Study
- Actions/next steps
- Integrated Resource Planning
- Southwest regional overview
- Southern Lake Huron pilot project
- How to stay involved
- Q&A

4

SUZANNE:
Today's agenda consists of:
- Our engagement process & webinar objectives
- Pathways to net zero study
- Actions/next steps
- Integrated Resource Planning
- An overview of the Southwest region
- The Southern Lake Huron pilot project, and
- How you can stay involved
- We'll finish the session off with a question and answer period

While this meeting is an opportunity for you to share feedback and local knowledge, I'd like to be clear that it isn't a forum to discuss government, environmental or regulatory policy or proceedings.

• Lines will be muted during the webinar, and
• If you have any questions, please enter them into the chat function and a moderator will address it during the Q&A

Engagement process and objectives

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IRP engagement process:

- An open and public engagement process where participation and feedback is encouraged.
- The engagement process is ongoing with sessions happening throughout the year.
- We welcome comments on how to improve the process. Comments can be shared with IRP team members or through the 'Have Your Say' online feedback form.

Objectives of the webinar are to:

- Highlight the benefits of a Diversified Pathway to Net Zero study in Ontario.
- Introduce Natural Gas Integrated Resource Planning (IRP).
- Provide an update on natural gas planning underway within the region.
- Seek feedback on the demand forecast for the region to confirm current customer growth information.

5

SUZANNE:
This webinar is the first of many IRP engagement sessions and is intended to be an ongoing dialogue with attendees to help inform regional planning. Today's session will focus on explaining how Enbridge is considering the energy transition in Ontario and provide background on how Enbridge approaches regional planning and integrated resource planning. This stakeholder session is important to better understand the local initiatives and policies that may affect natural gas demand. Feedback received will help inform our demand forecasting process and allows us to plan for the future more prudently. Subsequent sessions will look to define the needs of the community and provide potential integrated resource planning options, which will be discussed in future slides.

There are federal and provincial emission reduction targets, and Enbridge Gas is committed to supporting achievement of these targets. Today we're going to be speaking about a few key areas we are focused on. We'll talk about integrated resource planning and the role it plays in supporting the energy transition as well as initiatives we are currently engaged in including a study commissioned by Enbridge Gas to understand the role our system can play in Ontario's energy future.

The objectives of this webinar are to:

- Highlight the benefits of a Diversified Pathway to Net Zero in Ontario
- Introduce Natural Gas Integrated Resource Planning
- Provide an update on natural gas planning underway within the region, and
- Seek feedback on the demand forecast for the region to confirm current customer growth information

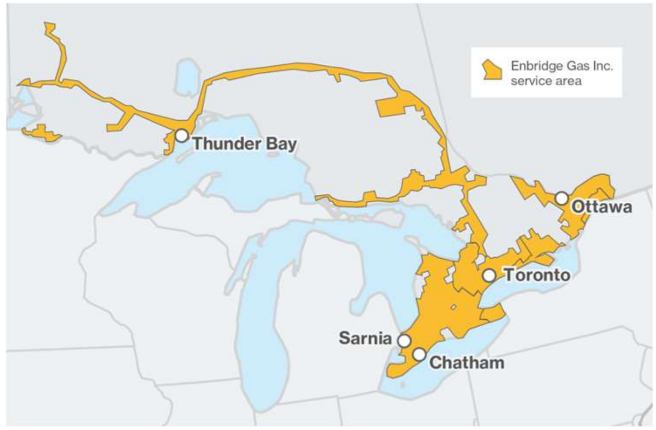
Enbridge Gas Inc.

ENBRIDGE
Life Takes Energy

North America's largest natural gas storage, transmission and distribution company

We deliver the energy that enhances people's quality of life.

- **Values:** Safety, Integrity, Respect, Inclusion.
- **Ambition:** To be the sustainable and reliable energy provider of choice.
- **Experience:** 170+ years of experience in safe and reliable service.
- **Distribution business:** 3.9M customers, heating >75% of Ontario homes.
- **Dawn Storage Hub:** Canada's largest integrated underground storage facility and one of the top gas trading hubs in North America.
- **Leading Ontario's transition to net-zero emissions** Advancing conservation, renewable gases and clean technologies for heat, transportation and industrial processes.



Formed Jan. 1, 2019 from the amalgamation of Union Gas Limited and Enbridge Gas Distribution.

6

SUZANNE:
Before we move into information about the Pathways to Net Zero, here are a few highlights about Enbridge Gas:

Enbridge Gas Inc., based in Ontario, is the largest gas utility in North America for volume send out and the third largest in number of customers.

We exist to deliver the energy that enhances people's quality of life and have done so for 175 years.

We safely provide the dependable energy our 3.9 million customers depend on to warm their homes, power their vehicles, and help produce and move the goods we use every day.

We have approximately 3,945 employees (as of June 2022).

We manage $26.59 billion in assets, including natural gas storage facilities and the pipelines that bring gas to homes and businesses.

Each year we invest more than $1 billion in capital in the province—on items like steel for pipelines and systems upgrades—and another $1 billion in operations—including equipment leases, power consumption and wages.

Enbridge Gas aims to be the sustainable energy provider of choice is innovating and adapting our business model to accelerate the transition to a net-zero emission future in Ontario. We are focusing our efforts in three areas:

- Using less through conservation (programs for residential, business and

industrial customers)
- Transitioning to renewable gases (renewable natural gas and hydrogen), and
- Advancing clean technologies for transportation, building heat and industrial processes (such as CNG and RNG, hybrid heating, geothermal, and carbon capture)

Enbridge Gas has contributed over $4.1 million to community and charitable organizations across Ontario.

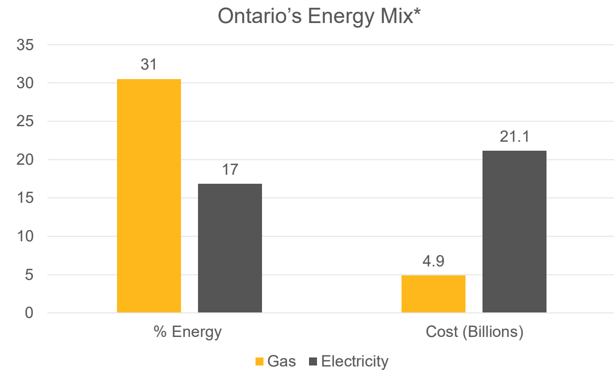
Enbridge Gas is owned by Enbridge Inc. and is proud to be Canadian-based leader in energy transportation and distribution.

And with that I will pass the presentation over to Heidi.

Pathways to Net Zero Emissions for Ontario

Ontario's energy systems

Ontario's energy system reality
Natural gas provides almost twice the energy needs of Ontarian's and less than ¼ the cost



*% Energy: Canada's Energy Future 2021 report's database. Cost Electricity: $18B operating revenues, OEB's 2021 yearbook and $3.1B Renewable Cost Shift Subsidy, Financial Accountability Office of Ontario's Report, Ontario's Energy and Electricity Subsidy Programs, February 2022. Cost Gas: Total operating revenues for Ontario's gas distributors, OEB's 2021 yearbook.

HEIDI:
Today, natural gas is a critical component of Ontario's current energy supply. Approximately 75% of Ontario homes rely on natural gas for home and hot water heating. Overall, 30% of Ontario's energy, almost double that of electricity, is served by natural gas. That means that natural gas serves almost twice the energy needs of Ontario than electricity, and at less than ¼ of the cost.

In addition, Ontario has a reliable electricity supply today because of natural gas-fired generation. Electricity can't be efficiently stored, and renewable power requires a backup that can ramp up quickly to meet Ontario's energy needs when the wind doesn't blow, the sun doesn't shine, or above-ground infrastructure is impacted by climate events like ice or high winds.

Within the next 20 years, energy demand is set to increase by 25 percent as forecasted by the International Energy Agency (IEA).

At the same time, residents of Ontario are concerned about reducing carbon emissions. Under the Paris Agreement, Canada committed to a target to reduce GHG emissions by 30% below 2005 levels by 2030. In April 2021 Prime Minister Trudeau increased Canada's 2030 emissions reduction target to 40-45%.

Some suggest that the best way to address climate change and reduce emissions is to eliminate fossil fuels and electrify everything. While this sounds like a simple solution, in our view, a focus on electrification overlooks market-ready, low and zero carbon solutions that can be delivered at a significantly lower cost by integrating existing natural gas and electric systems, versus an electric-only option.

Enbridge Gas believe that a coordinated approach to energy system planning – between natural gas and electricity - is required for a successful energy transition.

Enbridge's role in Ontario's energy transition

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- With approximately 30% of Ontario's emissions coming from the use of natural gas, Enbridge Gas will have an important role in energy transition.
- Enbridge Gas is committed to supporting government with the achievement of their clean energy plans.
  - Actively working on solutions to help meet Ontario's energy needs, while reducing emissions cost effectively.
  - Proactively engaged a consultant to evaluate energy system pathways to net zero.
  - Enbridge has set a net zero by 2050 target for emissions from our own operations, with an interim goal of reducing emissions intensity by 35% by 2030.
- The gas distribution system in Ontario is a resource that can be leveraged to enable further GHG reductions beyond 2030, including net zero.

HEIDI:
We recognize that energy transition is starting to unfold in Ontario and there are aggressive emission reduction goals set by Canada.

We recognize that our natural gas system and the product that we deliver will need to change to support these emission reduction goals – given that approximately 30% of Ontario's emissions are from the use of natural gas.

We are committed to supporting energy transition in Ontario, and we have taken the following steps so far:

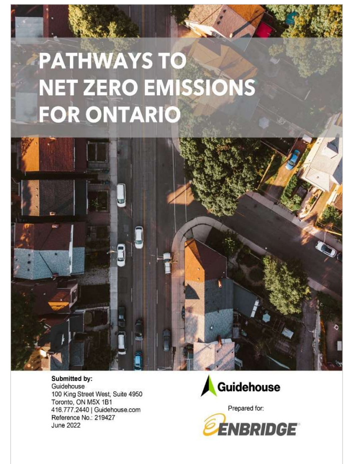
- We've actively investing in low-carbon solutions that support cost-effective emission reductions – while continuing to safely and reliably meet Ontario's energy needs
- We've proactively engaged a consultant, Guidehouse, to evaluate energy system pathways to net-zero to help determine exactly what our role can be in the transition. I'll speak more to this study on the next few slides.
- We've set net-zero targets for emissions from our own operations

Enbridge Gas's distribution, transmission and storage assets are vast and invaluable in providing reliable and resilient energy to Ontario. Our system can support a net-zero future – and the extent to which our system can be utilized in the transition must be further analyzed and understood before any decisions are made with regards to the best pathway forward in Ontario. Enbridge has the scale and experience to support the transition to a net-zero future and is delivering innovative solutions across the sector.

Pathway to Net Zero Study

Two scenarios for Ontario's energy sector

- Enbridge Gas engaged Guidehouse to evaluate two pathways to net zero:
  - **Diversified Pathway:** end use electrification used in balance with low- and zero-carbon gases and natural gas paired with carbon capture.
  - **Electrification Pathway:** deep electrification of all sectors with low- and zero-carbon gases and carbon capture used only where no reasonable alternative energy source exists.
- For each, the study assessed the overall feasibility based on costs, GHG emission reductions, system reliability and resiliency.
- The study also identifies what investments are needed in electricity, hydrogen and methane supply capacity, storage and infrastructure.



10

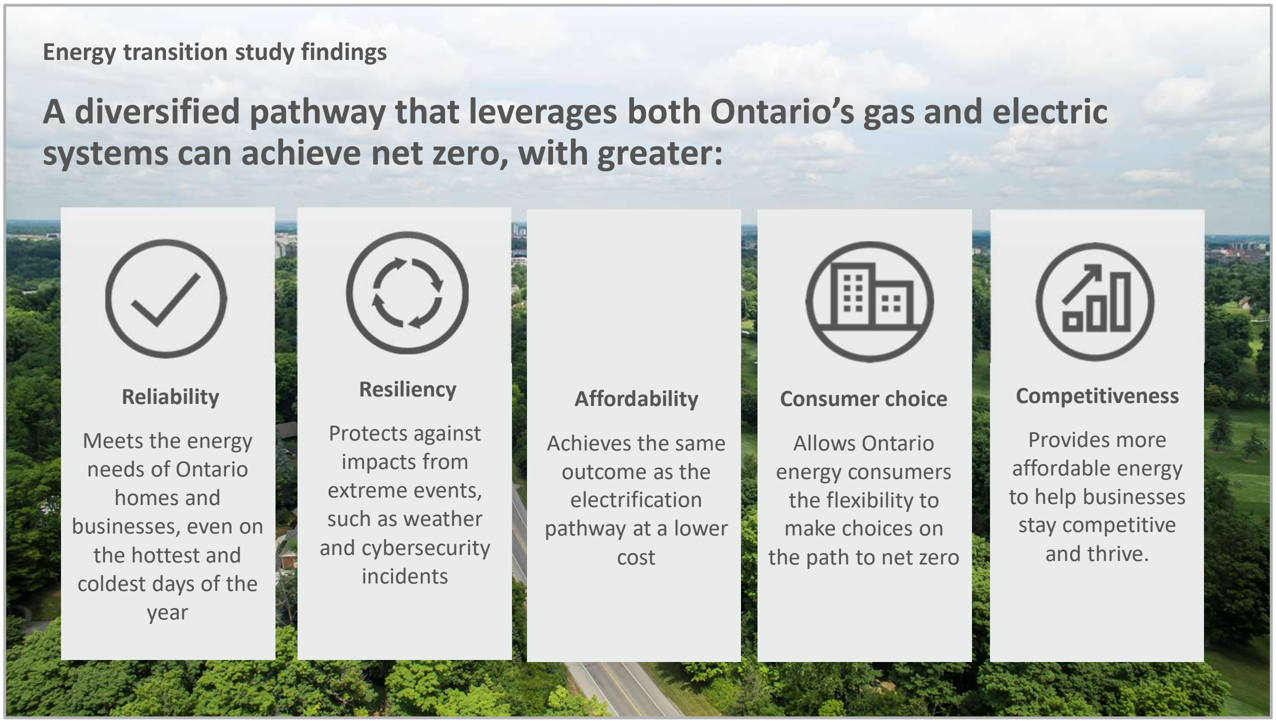
HEIDI:

As mentioned previously, Enbridge Gas engaged a consultant, Guidehouse, to conduct a scenario analysis that examined two pathways to net-zero in Ontario.

For each scenario, the study assessed the overall feasibility of the pathway based on costs, GHG emission reductions, system reliability and resiliency.

The study also identifies what investments are needed in electricity, hydrogen and methane in terms of supply capacity, storage and infrastructure.

The study included sensitivity analyses which looked at how various changes in assumptions impacted the scenarios. The next few slides dive into the details; however, Guidehouse found that the Diversified scenario with hybrid heating was the most optimal approach to achieving net-zero in Ontario by 2050. All results in this presentation are based on this Diversified scenario.



HEIDI:
The study found a Diversified Pathway is the most practical approach to reach net zero in Ontario, with several key benefits in reliability, resiliency, affordability, ensuring consumer choice and competitiveness.

1. Reliability: Energy production from wind and solar requires energy storage and dispatchable generation capabilities to maintain reliability. The natural gas system include vast and cost-effective underground storage, which provides great reliability during peak demand periods.
2. Resilience: Resilience is enhanced by balancing supply and demand, and when energy sources can complement one another. The use of underground distribution and transmission networks mitigate the increased risk during extreme inclement weather and potential cyberattack.
3. Affordability: The Diversified pathway achieves net zero at a lower cost to Ontarians. This is due to leveraging the existing natural gas system that can deliver low – and zero carbon energy, and avoidance of the build-up of the electric system to meet peak energy demands.
4. Consumer Choice: We know that seamlessly transitioning millions of gas customers to lower emitting solutions won't be easy. The Diversified Pathway allows customers to transition to the energy solution that best meets their needs by enabling this wider range of options. This will create a more achievable pathway as customers can make choices that reduce their GHG emissions while also meeting their individual needs.
5. Business Competitiveness: Business competitiveness in Ontario is

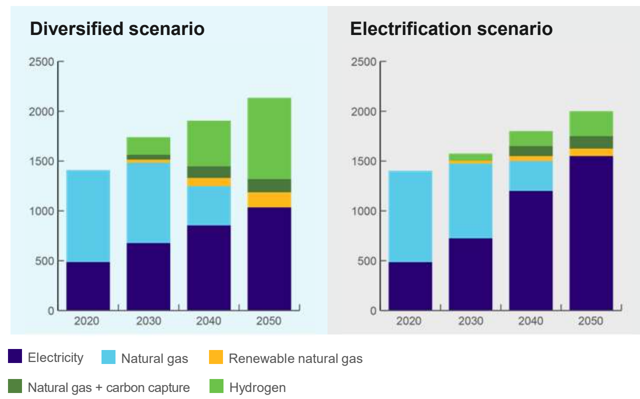
maintained by allowing the costs of operating and maintaining the gas system to be spread amongst millions of users as opposed to concentrating the costs across those industries in hard-to-abate sectors that have no great energy alternative.

Study findings

Low-carbon gases and carbon capture are key to net zero

- Both scenarios rely on low-carbon gases such as natural gas with carbon capture storage, renewable natural gas (RNG), and hydrogen.
- The Diversified Pathway uses low-carbon gases (predominantly hydrogen) to:
  - Heat buildings
  - Provide peak energy supply, which costs less than the Electrification Pathway
  - Enhance grid reliability, as it acts as a storage asset for peak period power generation

Energy supply mix by decade



12

HEIDI:
In both scenarios, Ontario will transition from natural gas to renewable gases (like hydrogen and renewable natural gas - RNG) and some natural gas will be paired with carbon capture for sectors that can't be electrified, such as high-temperature industrial processes and heavy-duty long-haul transportation.

By 2050, the diversified net zero path includes a higher mix of hydrogen, RNG and conventional natural gas paired with carbon capture and storage.

Hydrogen plays a large role in the Diversified pathway:
- Its uses include:
  - Building heat, medium and high-temperature industrial processes, and heavy-duty transportation
  - Hydrogen can be stored in pipelines and used for power generation during peak power, which increases system resiliency.

The amount of hydrogen in the Diversified Pathway is a key driver of resiliency and lowering the cost of this scenario – building dedicated wind turbines, electrolyzers and injecting hydrogen into the gas distribution system is a lower cost solution than building out additional electric infrastructure.

Domestic low- and zero- carbon gas developed in Ontario will reduce Ontario's reliance on gas imports.

*The energy breakdown is relative to the energy demand served by the gas and electricity systems. This excludes energy demand from sectors outside the scope of the study, such as agriculture

Path to Net Zero

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- Optimizing the diversified scenario requires coordinated gas and electric system planning.
- Leveraging both electric and natural gas energy systems creates:
  - Greater reliability and resiliency, as multiple systems can provide more protection against extreme events, such as inclement weather.
  - Less costly GHG reductions, as delivering low carbon fuels via existing gas infrastructure can significantly limit the need to build out peak electric infrastructure.
- To drive the benefits of energy systems working together, energy policy should focus on achieving GHG reduction targets, not electrification.

13

HEIDI:
Optimizing the Diversified Pathways requires coordination of gas and electric system planning.

- By leveraging both electric and natural gas energy systems, we can create:
  - Greater reliability and resiliency, as multiple systems can provide more protection against extreme events, such as inclement weather.
  - Less costly GHG emission reductions, as delivering low carbon fuels via existing gas infrastructure can significantly limit the need to build out peak electric infrastructure.

To drive the benefits of energy systems working together, energy policy should focus on achieving GHG reduction targets, and not simply electrification.

Actions/next steps

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Actions to achieve net zero

"Safe-bet" actions to take today to reach net zero:

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Maximize energy efficiency

Reduce energy use.

Optimize and coordinate energy system planning

Coordinate electric and gas system planning.

Invest in low-carbon gases

Transition to increasing amounts of RNG and hydrogen over time.

Utilize carbon capture and storage

Invest in CCS for heavy industry and blue hydrogen production.

15

HEIDI:

Regardless of the pathway the province takes to achieve net-zero, there are some actions that Enbridge Gas believes are safe bets. These actions are considered safe bets because they can deliver near term GHG emission reductions, support either pathway, and/or maintain optionality until the best pathway is chosen.

Safe bet actions include:

- Continuing to focus on delivering energy efficiency programs, with a focus on maintaining alignment with federal, provincial and municipal programs to ensure the costs and impacts are minimized.
- Investing in greening the gas supply through low-carbon gases, including RNG and hydrogen.
- Investing in carbon capture, utilization and storage for heavy industry and hydrogen production.
- Optimizing and integrating gas and electric systems through coordinated system planning and through physically integrating systems in buildings through hybrid heating.

Actions to achieve net zero

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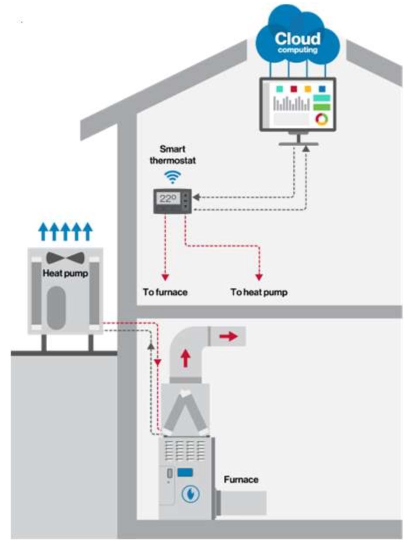
Coordinated energy system planning example:

- **Hybrid heating** combines natural gas-fired furnaces with electric heat pumps and smart controls to reduce GHG emissions practically and affordably.
- An electric air-source heat pump heats the home when temperatures are moderate and electricity rates are low. A gas furnace support home heating as outdoor temperatures drop.
- Retrofitting equipment, rather than replacing it, is simpler and reduces costs for homeowners.



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HEIDI:
Hybrid heating is a great example of how the gas and electric systems can be coordinated to ensure Ontarians have the energy they want and when they need it, while reducing GHG emissions.

Hybrid heating combines an electric air-source heat pump with a natural gas furnace and smart controls. When temperatures are moderate, it uses the heat pump, switching to the gas furnace when temperatures are colder.

The Pathways to Net Zero study showed that by increasing the amount of hybrid heating in the diversified pathway, the peak electric system demand is lower than just using heat pumps on their own, and this lowers the overall costs for Ontario to achieve net zero.

Integrated Resource Planning

Integrated Resource Planning

- Integrated Resource Planning (IRP) is an enhanced planning strategy and process.[1]
- Enbridge Gas evaluates non-pipeline alternatives that could be used to defer or avoid implementing a traditional pipe project to meet a system need.
- Consideration is given to safety, cost-effectiveness, and the ability for alternative solutions to meet customer demands reliably.

[1] IRP Framework was published by the OEB on July 22, 2021.

18

CHRIS:
Before we go any further on our discussions of Integrated Resource Planning it is important to outline the objectives of the Stakeholder and Indigenous Engagement process that this webinar is a part of. IRP regional stakeholder activities are important to better understand the local initiatives and policies that may affect natural gas demand. This is then incorporated into our demand forecasting processes and allows us to plan for the future more prudently.

In other words, it helps us to find alternative ways to meet customer demand for energy without adding more or upsizing our pipeline infrastructure.

IRP alternatives (IRPAs)

Non-pipeline alternatives can include:

- **Demand side alternatives:**
  - Lowering energy use through energy efficiency programs such as Enhanced Targeted Energy Efficiency (ETEE) programs or Demand Response programs
- **Supply side alternatives:**
  - Delivering more energy without adding new pipeline using compressed natural gas (CNG) or liquified natural gas (LNG)
  - Displacing conventional natural gas with carbon-neutral renewable natural gas and hydrogen
  - Adding supply through upstream deliveries

Alternatives can be implemented individually or in combination to meet the system need cost-effectively and within the required timeframe.

19

CHRIS:
The Ontario Energy Board approved an IRP Framework that allows Enbridge to offer non-pipeline alternatives to traditional pipeline infrastructure, including demand side and supply side alternatives.

The objective of demand side alternatives is to lower the peak demands of customers. We can achieve this through energy efficiency programs that reduce the peak consumption of the customer. Or we can reduce the peak demands of customers through a demand response program by shifting the customers energy demands from a peak period to an off-peak period. An example of demand response would be shifting a customer's morning heating load to start at 4 to 6 am rather than 7 to 9 am thereby reducing the peak demands in that area.

The objective of gas supply alternatives is to increase or maintain the gas supply to our customers without adding incremental natural gas pipe facilities. We can meet customers energy needs with a variety of supply side alternatives including delivering compressed or liquid natural gas via transport trailers, displacing conventional natural gas with carbon-neutral renewable natural gas or with hydrogen.

Enbridge will look at each of the alternatives individually and in combination to try to meet the energy needs of our customers.

IRP assessment process

Enbridge Gas uses a four-step IRP assessment process to determine the best approach to meet system needs:

1. Identification of constraints
2. Binary screening criteria (pass/fail)
3. Two-stage evaluation process
   – Technical evaluation
   – Economic evaluation
4. Periodic review

The IRP assessment process allows Enbridge Gas to focus on investments where there is a reasonable expectation that a proposed project could efficiently and economically meet the system need.

20

CHRIS:
Enbridge uses a 4 step assessment process to determine the most optimal solution. First, we identify the constraints on our system

First step - Identification of Constraints:
•Bi-annual refresh of the Company's Asset Management Plan (AMP) to identify system constraints and capital investments
•Kurtis will discuss this process in a few minutes

Second step - Binary Screening Criteria (Pass/Fail)
•The OEB approved a set of screening criteria for Enbridge to screen its projects. Projects that fail the screening will not be assessed for IRP alternatives and projects that pass will move to a two stage evaluation process.
•Emergency Safety Issue
•Timing (less than 3 years away)
•Customer-Specific Builds
•Project is part of Community Expansion and Economic Development
•Pipeline Replacement and Relocation Projects where the cost is less than the minimum project cost of an LTC approval ($2M)

Two-Stage Evaluation Process
•Technical Evaluation – Assesses the technical viability of potential IRPAs to reduce peak demand to the degree required to meet the identified system need, using best available information to determine whether an IRP Plan including one or more IRPAs would be a viable option.
•Economic Evaluation – The three-phase economic test that compares the IRP plan(s) to the pipeline option to determine which alternative is optimal.

Periodic Review

•On-going assessment of system needs and updates where required

How does IRP support energy transition?

ENBRIDGE
Life Takes Energy

- Energy landscape in Ontario is evolving
- IRP is an energy transition initiative
- IRP is a bridging solution

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CHRIS:

- As the energy landscape continues to evolve, there is a growing interest in low carbon alternatives to meet energy needs and as the largest natural gas distributor in Ontario, Enbridge Gas knows it will play a meaningful and integral role in the province's path towards energy transition.

- Enbridge Gas considers IRP as a key Energy Transition initiative. IRP alternatives may defer pipeline infrastructure which allows Enbridge Gas to manage the uncertainty in the energy sector until energy policy is more concrete, with clear decarbonization pathways identified.

- In other words, IRP is a stopgap or a 'bridging' solution in the short-term allowing Enbridge Gas to either reduce natural gas demand with customer programs or provide supply-side alternatives to defer infrastructure builds, until energy policy is better understood at regional and provincial levels.

- Enbridge Gas is committed to supporting the province, municipalities and Indigenous communities in achieving their clean energy goals. Annual IRP stakeholder activities will support on-going dialogue between all parties to ensure energy and climate plans are known and factored into Enbridge Gas's system planning.

Now I will turn it over to Kurtis Lubbers to discuss how we plan our natural gas system.

How we are planning our system today with IRP

- Demand forecast
- Hydraulic modelling
- Asset Management Plan
- IRP assessment process

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KURTIS:
The Asset Management planning process is an annual and continuous process resulting in a new Asset Management Plan or an Addendum to the previous years Asset Management Plan.

Traditionally, Enbridge Gas would respond to growing customer demand with the installation of a new or bigger pipe. Today, Enbridge Gas evaluates each system need to determine if an alternative can be implemented. Alternatives and smaller pipe sizes are also considered for facilities or infrastructure requiring replacement.

Enbridge Gas utilizes an economic and evaluation forecast to anticipate future customer additions. Multiple factors are incorporated into the demand forecast, including:

- Input from Enbridge Gas Regional Offices and Districts
- Municipal Zone Plans
- Developer Plans
- Energy Transition Assumptions (i.e., Low Carbon Trends)
- Municipal GHG Targets and Plans
- Declining Average Use per customer assumption
- Other

*This information may be adjusted to reflect regional insight of locally known developments and timing through our regional offices, and/or feedback received through our IRP stakeholder activities (and included as part of EGI's Asset Management Plan (AMP) 'refresh' on an on-going basis (approx. every 2 years)).

The future customer additions information is then appended to the existing customer base and a future 10-year infrastructure forecast is created for the piping systems. Hydraulic models are run with the above inputs and reinforcement projects (i.e., growth projects) are identified where system constraints appear. Annual simulation and verification of the hydraulic models are run to ensure the model is reliable in estimating general demand on the system.

The results of the future forecast are documented, and reinforcement projects are included in the EGI Asset Management Plan.

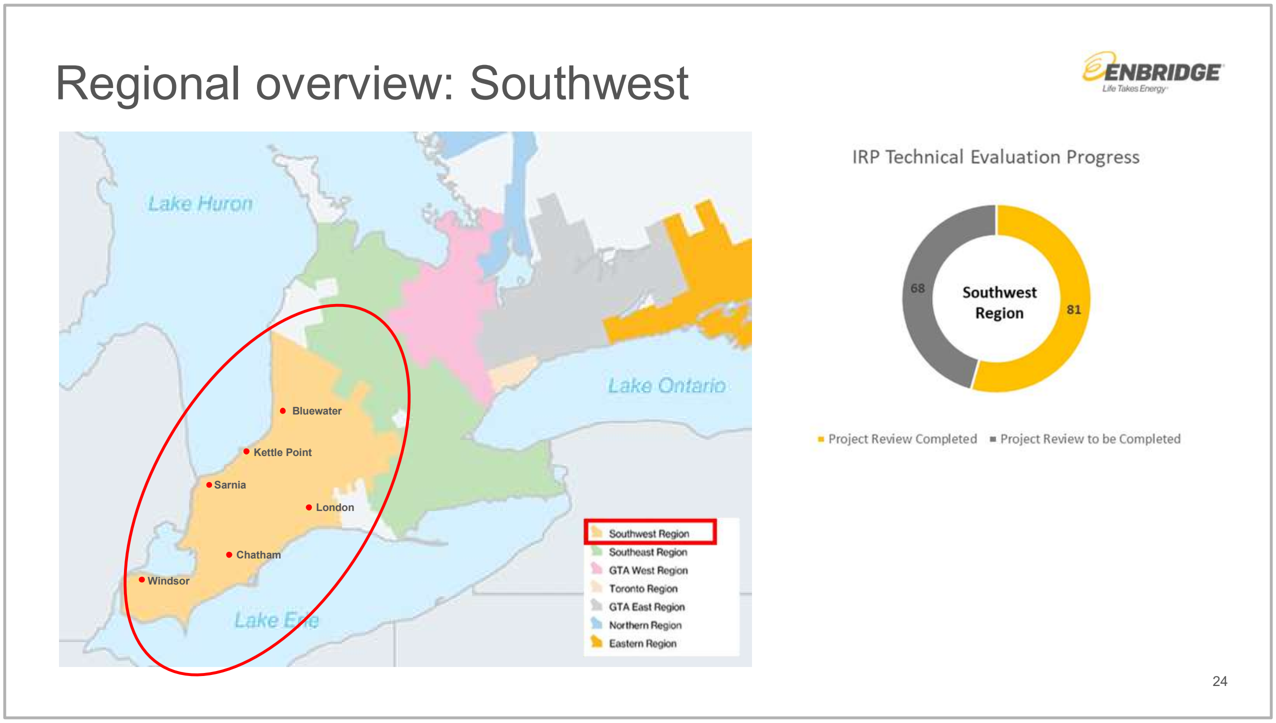
Projects are screened through the IRP Assessment Process for non-pipeline alternatives that could meet the system constraint or need. Projects that do not pass IRP screening, or are ineligible for an IRP alternative, are then reviewed as part of the traditional pipeline process.

Enbridge Gas shares system needs from the AMP annually with stakeholders at a regional level to seek feedback that EGI has the gas demand forecast for each region ‘right’. This is part of the process that we are engaging in right now with the people on this webinar.

Enbridge Gas applies to the OEB for regulatory approval with either an IRPA Project application for projects that can be met with an IRP alternative(s) or a traditional Leave-To-Construct (LTC) Application for projects that require a traditional pipe to meet the need technically and cost-effectively.

Southwest regional overview

ENBRIDGE
Life Takes Energy



KURTIS:
Our regional overview provides us with locational details on areas in the Southwest region, including major centers like London, Sarnia, Windsor, and Chatham.

The Southwest region contains the cities from Woodstock and London, all the way southwest to Windsor and Leamington.

Notable trends in the region include:

- significant energy consumers in Sarnia where there are numerous refineries
- Chatham-Kent / Leamington / Windsor, with high demand due to expanding agriculture greenhouse operations, particularly in Essex County.

To date, the Enbridge team has completed technical evaluations for about <u>half</u> of the 149 projects in the Southwest Region. 4 of which have passed the technical evaluation and will be assessed from a financial perspective for IRP potential.

We are currently in the process of implementing an IRP pilot project in the Southern Lake Huron Area that we will discuss further in the next slides.

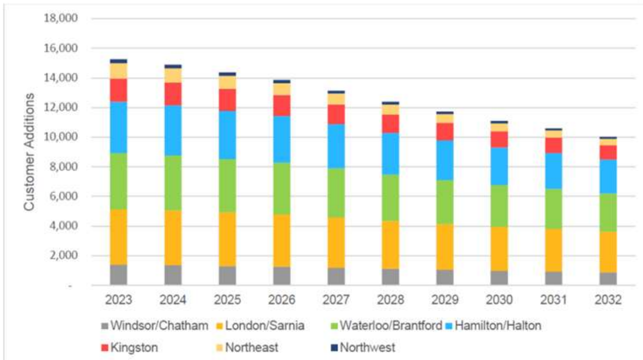
While the Enbridge team is still assessing potential other IRP projects from both a technical and financial perspective, initial areas of interest (based on the 2023-2032 Asset Management Plan) include Bluewater, Kettle Point and London area.

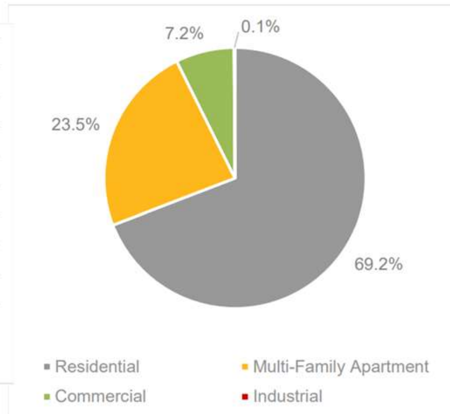
A number of factors are considered when evaluating future customer additions and natural gas demand forecasts.
Enbridge Gas appreciates stakeholder feedback to help inform our areas of focus for potential IRP projects to confirm the demand forecast as well as information that may affect implementation.

Enbridge Gas is accepting feedback through the form that will be delivered to you following this webinar as well as on our webpage through the “Have Your Say” function.

Meeting regional energy needs: customer additions

ENBRIDGE
Life Takes Energy





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KURTIS:
Before we start talking about the specific areas of growth in the Southwest region we thought it would be helpful to talk first about the projection of customer additions over the next 10 years. On this slide Windsor & Chatham are indicated in grey and London & Sarnia in darker yellow. While Windsor & Chatham have lower connection numbers, a portion of these are very large green houses in the Kingsville / Leamington area which have high demands.

The customer growth forecast is a projection of how many new customers will be attached to the distribution system over the next 10 years. Development of this forecast considers attachments, additions and conversions including detailed information originating from direct contact with builders, developers and municipalities.

For instance, a primary data source used in predicting growth is historical housing starts from Canadian Mortgage and Housing Corporation. For growth projections particularly in the apartment sector, housing starts are much higher than the customer additions in the sector. Based on known applications and development projects, a consolidation of forecasts and known projects are used to determine the final customer growth forecast.

These two graphs show the customer System Reinforcement Plan growth forecast, including energy transition assumptions, while the chart on the right indicates the breakout by sector of the anticipated customer growth categories.

Over the 10-year forecast, the number of customer connections decline when factoring in energy transition.

Customer additions, connections and growth are projected to remain relatively flat in the short term and slightly decline thereafter.

The potential impacts of Bill 23 – The more homes build faster act, are still being assessed and once those impacts are known they will be factored into the demand forecast. It is anticipated that in those regions that encompass green belt lands may see changes in the demand forecast due to increased customer additions.

Urban density in EGI’s franchise areas is reflected in the fact that apartments have been accounting for a larger share of total housing starts. Given that one building counts as a single customer because of the use of bulk meters, lower customer additions do not reflect lower loads served, but simply a shift in the makeup of the sectoral source of growth.

Southern Lake Huron Pilot Overview

Enbridge is looking to develop and implement two IRP pilot projects as directed by the OEB – one of which is located in the Southern Lake Huron area.

Key Pilot Objectives

- Develop an understanding of how to design, deploy and evaluate potential Enhanced Targeted Energy Efficiency (ETEE) and Demand Response (DR) programs.
- Gain insight into how potential ETEE measures & DR programs impact peak hour demand.

Potential IRPAs

- Demand Side: Enhanced Targeted Energy Efficiency (ETEE)
- Demand Side: Demand Response (DR)

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WHITNEY:
Under the direction of the OEB, Enbridge is looking to develop and implement two IRP Pilots Projects. One of which is located in the Southern Lake Huron area, which includes the City of Sarnia and the Town of Plympton-Wyoming in the County of Lambton.

The key focus of these pilots will be to explore and gain learnings and a better understanding of two key IRP Alternatives - specifically focusing on enhanced targeted energy efficiency (ETEE) and demand response (DR) programs.

To provide a bit more insight into what these two alternatives include, ETEE involves offering targeted energy efficiency programs, such as providing incentives towards energy efficiency equipment to home owners and businesses in the pilot areas, in efforts to reduce the peak period natural gas demand in that area. While traditional energy efficiency programs have been in place for some time, using them to reduce peak demand requires more investigation. And these pilots will aim to better understand how to design, deploy and evaluate an ETEE programs.

The other IRP alternative we're interested in learning as part of this pilot is Demand Response, and this involves offering a program that would target primarily residential customers and provides incentives to participants to lower their thermostats during peak times as requested by Enbridge Gas, essentially shifting load off peak period gas demand.

This Southern Lake Huron IRP pilot project area is unique in that most of the system is already equipped with meter reading technology which allows for more granular data to be collected from customer’ meters, and this is a critical piece in supporting our objectives to evaluate and understand the impact these alternatives have on peak hour demand.

Feedback and next steps

- Feedback from stakeholder engagement initiatives is necessary to inform our IRP activities.
- We welcome feedback on the following:
  - Information that could affect natural gas demand that Enbridge Gas has not considered for this area and/or that you believe Enbridge Gas should be aware of, such as:
    - New residential/commercial
    - Industrial developments
    - New Municipal or Community Energy Plans
    - Municipal energy policy, etc.
- Feedback on the specific area's discussed today including potential IRPA opportunities.

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SUZANNE:

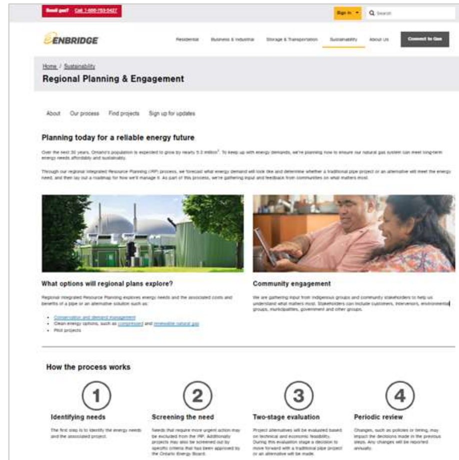
- Feedback from stakeholder engagement initiatives is important part of informing our IRP activities.
- We welcome feedback on:
  - Information that could affect natural gas demand that Enbridge Gas has not considered for this area or that you believe Enbridge Gas should be aware of, such as:
    - New residential or commercial developments
    - Industrial developments
    - New Municipal or Community Energy Plans, and
    - Municipal energy policy, etc.
- We would also like to hear feedback on the specific area's discussed today including potential IRPA opportunities.

How to stay involved

Visit our Regional Planning webpage to:

- Sign-up for email updates to receive information on upcoming stakeholder events and webinars
- Register for events
- Review regional pages that include all IRP projects in your community
- Submit feedback through ‘Have your Say’
- Search for other IRP information as required

Sign-up for email updates today!



enbridgegas.com/sustainability/regional-planning-engagement

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SUZANNE:

Visit our Regional Planning webpage to:

- Sign-up for email updates to receive information on upcoming stakeholder events and webinars
- Register for events
- Review regional pages that include all IRP projects in your community
- Submit feedback through the ‘Have your Say’ form on our webpage, and
- Search for other IRP information as required

Q&A

What is peak demand?
Peak demand is basically the time of the day or the peak hour the morning peak hour on the coldest day of the year or the coldest forecasted day of the year. That's what we design all our gas distribution systems to at Enbridge. It the 7-9 AM peak morning demand when everybody's using the most gas that they they're capable of using.

What is demand response?
Demand response is really shifting the firm demands of a customer or customers from a peak period to an off peak period. Enbridge is looking at this from a couple different ways. One would be the residential sector as Kurtis just mentioned shifting the heating demands from that peak period in the morning or night to an off peak period. We will also be looking at our larger industrial customers as well if there's a constraint in an area that we could perhaps talk to the industrial customers about shifting their demands from the daytime to the evening. You'll see that alot in the electricity sector where they move customers from peak to off peak. We're looking at this on the natural gas side as well. Just to be very clear demand response is really simply shifting the demands from a very a peak period to an optional period.

Do you have any preliminary results from the programs in London to convert older homes to heat exchange systems?
I think what we should do is we'll take down the respond in writing. We'll put that down on FAQ on our website. We don't have the full results yet, but when we do we'll publish those.

Regional Planning & Engagement

Planning today for a reliable energy future

Over the next 30 years, Ontario's population is expected to grow by nearly 5.3 million[1]. To keep up with energy demands, we're planning now to ensure our natural gas system can meet long-term energy needs, affordably and sustainably.

Through our regional Integrated Resource Planning (IRP) process, we forecast what energy demand will look like, determine whether a traditional pipe project or an alternative will meet the energy need, and then lay out a roadmap for how we'll manage it. As part of this process, we gather input and feedback from communities on what matters most.

What options will regional plans explore?

Regional Integrated Resource Planning explores energy needs and the associated costs and benefits of a pipe or an alternative solution, such as:

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- Conservation and demand management (/sustainability)

- Clean energy options, such as compressed (/sustainability/clean-transportation/compressed-natural-gas) and renewable natural gas (/sustainability/clean-heating/renewable-natural-gas)
- Pilot projects

Community engagement

We're gathering input from Indigenous groups and community stakeholders to help us understand what matters most. Stakeholders can include customers, intervenors, environmental groups, municipalities, government and other groups.

- Fall 2023 newsletter (/-/media/Extranet-Pages/Sustainability/regional-planning-and-engagement/newsletter/fall2023-irp-newsletter.pdf?la=en&rev=2460727649d14e6fb75fbeeacbdd952c&hash=9A52C3FD231FF1694125A0572EFD3483)

How the process works

1

Identifying needs

The first step is to identify the energy needs and the associated project.

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2

Screening the need

Needs that require more urgent action may be excluded from the IRP. Additionally, projects may also be screened out by specific criteria that has been approved by the Ontario Energy Board.

3

Two-stage evaluation

Project alternatives will be evaluated based on technical and economic feasibility. During this evaluation stage, a decision to move forward with a traditional pipe project or an alternative will be made.

4

Periodic review

Changes, such as policies or timing, may impact the decisions made in the previous steps. Any changes will be reported annually.

Find Integrated Resource Planning projects in your region

See how we're investing in our system to support future energy demand and implement lower carbon alternatives.

Current projects

Parry Sound Pilot Project

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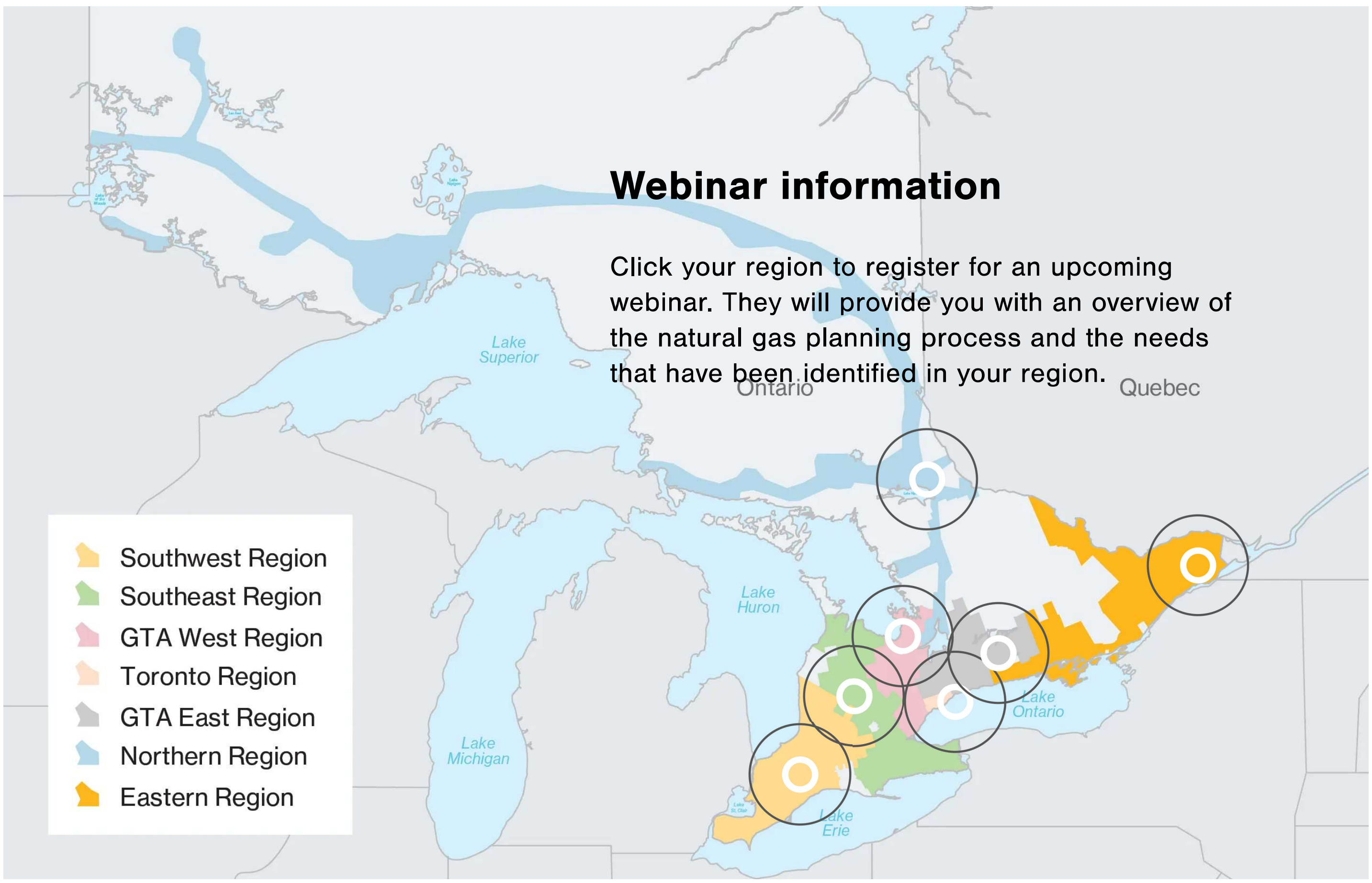
This pilot project is located within the Municipality of Parry Sound. The Integrated Resource Planning (IRP) alternatives being explored for this pilot project include supply and demand side alternatives, such as compressed natural gas (CNG) and an enhanced targeted energy efficiency (ETEE) program which will be explored to reduce peak demand on the system.

Learn more (/sustainability/regional-planning-engagement/parry-sound-project)

Southern Lake Huron Pilot Project

This pilot project is located within the City of Sarnia and the Town of Plympton-Wyoming in the County of Lambton. The Integrated Resource Planning (IRP) alternatives being explored for this pilot project include demand side alternatives, such as demand response and an enhanced targeted energy efficiency program which will be explored to reduce or shift peak demand on the system.

Learn more (/sustainability/regional-planning-engagement/southern-lake-huron-project)



Webinar information

Click your region to register for an upcoming webinar. They will provide you with an overview of the natural gas planning process and the needs that have been identified in your region.

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Frequently asked questions

What is IRP or natural gas planning?

How are Integrated Resource Planning projects determined?

What alternatives are being evaluated?

What are some current IRP projects?

Why do we need stakeholder feedback?

How does Integrated Resource planning support Enbridge Gas' energy transition?

How can I stay involved?

How does IRP affect general expansion efforts?

1. https://www.ontario.ca/page/ontario-population-projections

Natural Resources Canada / Ressources naturelles Canada

CanmetENERGY

Leadership in ecoInnovation

Source: https://ftp.maps.canada.ca/pub/nrcan_rncan/publications/STPublications_PublicationsST/329/329701/gid_329701.pdf
from Enbridge per EB-2022-0200 Exhibit J11.5

Cold-Climate Air Source Heat Pumps: Assessing Cost-Effectiveness, Energy Savings and Greenhouse Gas Emission Reductions in Canadian Homes

"CanmetENERGY- Ottawa leads the development of energy science and technology solutions for the environmental and economic benefit of Canadians."

Canada

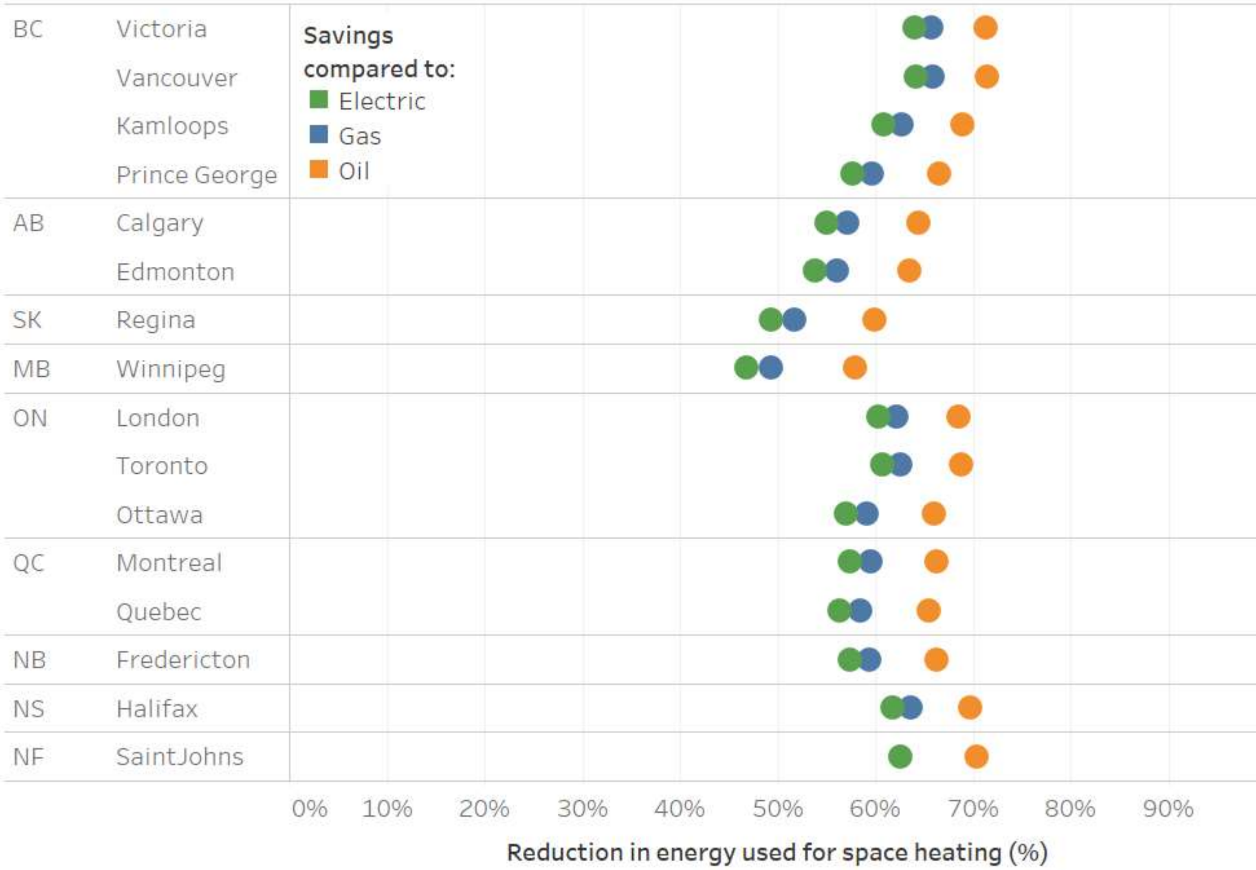

Figure 6: Reduction in annual energy used for heating in Archetype B (Post 1980s 2-story home), CC-ASHP vs electric, gas and oil furnaces

Figure 7 plots the reduction in annual greenhouse gas (GHG) emissions when the CC-ASHP system is compared to the reference heating systems. These results show that the emission impacts are much more sensitive to location than the site energy use. While the emissions associated with the gas and oil reference cases remain relatively constant between regions, the emissions associated with electricity vary province to province according to the carbon intensity of the generation infrastructure.

British Columbia, Manitoba, Quebec and Newfoundland generate the bulk of their electricity using hydro resources; Ontario also produces about 80-90% of its electricity from non or low emitting sources. In these regions, switching to heat pumps from gas or oil significantly reduces GHG emissions. But when compared to electric resistance, heat pumps offer negligible savings. In these provinces, electric resistance heating is nearly carbon free.

The opposite is true in Alberta, Saskatchewan, New Brunswick and Nova Scotia. These provinces use coal and gas-fired power plants to varying degree for the majority of electricity generation. In these locations, CC-ASHP technology delivers carbon savings relative to oil furnaces and electrical baseboards. When compared to gas furnaces, CC-ASHP systems lower emissions in New Brunswick, and increase emissions in Alberta and Saskatchewan. In Nova Scotia, gas furnaces and CC-ASHP systems produce similar emissions.

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

DECISION AND ORDER

EB-2020-0091

ENBRIDGE GAS INC.

Integrated Resource Planning Proposal

BEFORE: **Lynne Anderson**
Presiding and Chief Commissioner

Susan Frank
Commissioner

Michael Janigan
Commissioner

July 22, 2021

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

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1 OVERVIEW

Enbridge Gas filed an application with the OEB which requested that the OEB determine that the policy direction in its Integrated Resource Planning (IRP) proposal was reasonable and appropriate. Integrated resource planning generally refers to a planning process that evaluates and compares both supply-side and demand-side options to meeting an energy system need.

Enbridge Gas indicated that establishing policy guidance for Integrated Resource Planning would enable Enbridge Gas to be successful in considering IRP Alternatives to future facility expansion/reinforcement projects effectively and efficiently. This guidance would also be responsive to previous direction from the OEB that Enbridge Gas should improve its procedures for considering demand-side management as an alternative to pipelines and traditional facility infrastructure.

In response, the OEB is establishing a first-generation IRP Framework that provides direction on the OEB's requirements as Enbridge Gas considers IRP to meet its system needs. The expectation is that enhancements and improvements will be made in the future on the basis of the experience gained in Ontario with pilot projects and other IRP activities, drawing on successes achieved in other jurisdictions, and future policy direction. The IRP Framework is provided in Appendix A to this Decision and Order. Enbridge Gas is expected to begin integrating IRP into its existing planning processes, in a manner consistent with the IRP Framework, effective immediately.

Key elements of the IRP Framework are described below.

Definition of IRP: The IRP Framework establishes the following definition of IRP for Enbridge Gas:

> Integrated Resource Planning is a planning strategy and process that considers Facility Alternatives and IRP Alternatives (including the interplay of these options) to address the system needs of Enbridge Gas's regulated operations, and identifies and implements the alternative (or combination of alternatives) that is in the best interest of Enbridge Gas and its customers, taking into account reliability and safety, cost-effectiveness, public policy, optimized scoping, and risk management.

Guiding Principles: The OEB has determined that guiding principles are essential to the establishment of a robust IRP Framework. The IRP Framework cannot anticipate all situations that might occur in the consideration of alternatives to infrastructure builds.

The guiding principles will assist in providing consistent direction for IRP, particularly in these early years. The OEB approves guiding principles for the IRP Framework on reliability and safety, cost-effectiveness, public policy, optimized scoping, and risk management. These principles are consistent with the OEB's statutory objectives for natural gas.

Types of IRP Alternatives: The IRP Framework provides guidance on what types of IRP Alternatives Enbridge Gas may consider to meet an identified system need.

Demand-side programming, including geotargeted energy efficiency and demand response programs, is part of the IRP Framework. The demand-side IRP Alternatives are expected to target specific constrained areas and encourage the reduction of peak consumption. The IRP Framework will provide opportunities to gain experience on demand-side programming that focuses on reducing peak demand. Supply-side IRP Alternatives (e.g., compressed natural gas and renewable natural gas, and commercial or market-based alternatives such as peaking supply, third-party assignments, or exchanges), should also be considered, as should storage. For both demand-side and supply-side IRP Alternatives, Enbridge Gas is expected to consider procuring equipment or activities through the competitive market, where feasible and cost-effective.

Enbridge Gas also proposed non-gas IRP Alternatives, specifically electricity-based alternatives. The OEB has concluded that as part of this first-generation IRP Framework, it is not appropriate to provide funding to Enbridge Gas for electricity IRP Alternatives.

IRP Assessment Process: The IRP Framework includes a four-step process Enbridge Gas will use to determine the best approach to meeting system needs, including whether to pursue IRP Alternatives to address an identified need/constraint.

Identification of Constraints: Enbridge Gas will identify potential system needs/constraints up to ten years in the future in its Asset Management Plan, allowing time for a detailed examination of the potential for IRP Alternatives to meet these needs. The Asset Management Plan will provide the status of consideration of IRP Alternatives in regards to meeting system needs, and an updated version will be filed on an annual basis. The first version reflecting this updated process will be filed in Fall 2022.

The OEB is not requiring a more comprehensive review of Enbridge Gas's demand forecasting methodology that is used in identifying system needs at this time. Detailed examination of the ten-year demand forecast methodology is appropriately done at

Enbridge Gas's next rebasing application, at which time the Asset Management Plan will be filed as evidence.

Binary Screening Criteria: The IRP Framework includes screening criteria to select which system needs require further IRP consideration, in order to focus on those situations where there is a reasonable expectation that an IRP Alternative could efficiently and economically meet the need. This will include facility expansion/reinforcement projects where growth is the main driver.

The following criteria will generally exclude a system need from further IRP consideration:

- Emergent safety issues
- System needs that must be met in under three years
- Customer-specific builds where a customer fully pays for the incremental infrastructure costs associated with a facility project
- Community expansion projects driven by government legislation or policy with related funding aimed at delivering natural gas into communities
- Pipeline replacement and relocation projects costing less than the minimum project cost that would necessitate a Leave to Construct approval.

For customer-specific builds and community expansion projects, Enbridge Gas is encouraged to discuss demand-side management opportunities with customers to potentially reduce the size of the build.

Two-stage Evaluation: For system needs progressing past the binary screening, Enbridge Gas will undertake a technical evaluation to first determine if the IRP Alternatives considered can meet the identified need. If so, then Enbridge Gas will compare one or more IRP Plans to the baseline Facility Alternative, using an economic test, to determine the optimum solution to meet the system need.

A three-phase Discounted Cash Flow-plus test, including its focus on rate impacts (as identified in phase 1 of this test), will be the economic evaluation test used in the IRP Framework. This test assesses project benefits and costs from the utility, customer, and societal perspective.

The OEB recognizes that this test could be improved to better list and define the costs and benefits of facility projects and IRP Alternatives, and clarify how these costs and benefits should be considered within the test. Enbridge Gas is expected to study improvements to the Discounted Cash Flow-plus test for IRP, in consultation with the IRP Technical Working Group that will be established as part of the IRP Framework, and using IRP pilot projects as a testing ground. Enbridge Gas shall file an enhanced Discounted Cash Flow-plus test for approval as part of the first non-pilot IRP Plan.

If an IRP Plan is being proposed for the benefit of new customers, the results of the Discounted Cash Flow-plus test will assist the OEB in determining whether the proposed IRP Plan is compatible with the OEB's objective to facilitate rational expansion of transmission and distribution systems. Customer contributions could be applied to reduce cross-subsidization between new and existing customers.

Periodic Review: Enbridge Gas will review its IRP determinations if needed due to changing circumstances and identify any updates as part of an annual IRP report.

Allocation of IRP Risk: There are risks associated with the development of an IRP Plan and the selection of projects to address constraints.

One risk is that the OEB will have limited recourse at the project approval stage (for an IRP Plan or a facility project) if it believes that Enbridge Gas has not chosen the best option to meet a system need, because it may no longer be possible to implement alternative options without compromising safety or reliability. The OEB finds that Enbridge Gas is making considerable effort to improve its planning process, and this is expected to reduce this risk. The OEB is not requiring Enbridge Gas to seek approval for its determinations in the IRP Assessment Process, prior to project-specific applications (for an IRP Plan approval or a Leave to Construct approval). Enbridge Gas has considerable experience with Leave to Construct applications, including circumstances in which conditions of approval or modifications made to the original request have been required by the OEB. Furthermore, the OEB retains the authority to deny recovery of costs if it determines that Enbridge Gas was not prudent in considering alternatives.

A second risk is that an approved IRP Plan may not deliver the load reduction required to address a system need. With regards to who should bear the performance and cost risk associated with approved IRP Plans, the OEB has determined that prudently incurred costs associated with an approved IRP Plan will be eligible for cost recovery. The OEB acknowledges that there may be a greater degree of performance and cost risk associated with IRP Alternatives and IRP Plans in comparison with facility projects, and expects to take this into consideration in its prudence review. However, where Enbridge Gas does not act prudently or not in accordance with an approved IRP Plan, then it may be at risk for recovery of some portion of IRP investments that are deemed imprudent.

A third risk that is a concern for both infrastructure builds and for IRP Alternatives is stranded assets. At this time, the OEB will continue to emphasize the requirement to demonstrate prudence by Enbridge Gas, at both the system planning and project planning levels.

Stakeholder Outreach and Engagement Process: Enbridge Gas will use a three-component stakeholder engagement process for IRP. This will involve: (1) gathering stakeholder insight from existing channels; (2) holding regional stakeholder days on an annual basis focused on system needs identified in the Asset Management Plan and options to address these needs through IRP; and (3) project-specific consultation for specific proposed IRP Alternatives or IRP Plans in a specific geographic region. Enbridge Gas will also establish a website to facilitate the broad sharing of information on IRP stakeholdering efforts.

In addition to the three-component stakeholder process, the OEB will also establish an IRP Technical Working Group led by OEB staff, similar to the current OEB-administered Demand-Side Management Evaluation Advisory Committee. The IRP Technical Working Group will have an objective of providing input that is of value to both Enbridge Gas in implementing IRP, and to the OEB in its oversight of the IRP Framework. OEB staff will establish the IRP Technical Working Group, including a terms of reference, and the initial selection of Technical Working Group members, by the end of 2021. The OEB expects that the Technical Working Group's first priorities will be the consideration and implementation of IRP pilot projects, and enhancements or additional guidance in applying the Discounted Cash Flow-plus evaluation methodology. The IRP Technical Working Group will also be expected to review a draft of Enbridge Gas's annual IRP report, with the review coordinated by OEB staff. Material concerns that remain unresolved within the Technical Working Group will be brought to the attention of the OEB.

Indigenous Engagement and Consultation: No party has identified any direct material impact the IRP Framework could have on any Aboriginal or treaty rights. The IRP Framework is being established by the OEB following the receipt of input from many stakeholders including an Indigenous representative intervenor.

Enbridge Gas has indicated that it will make efforts to accommodate participation of Indigenous groups within its stakeholder engagement process and work with these groups as appropriate to address any concerns. The OEB endorses this approach.

There is insufficient information on the record at this time to determine which Indigenous communities would be impacted by specific system needs and the potential solutions (IRP Plans or facility projects), and what impact, if any, the individual IRP Plans might have on Aboriginal or treaty rights. In addition to any broader stakeholder engagement with Indigenous groups, Enbridge Gas is required to conduct consultation with respect to any potential impacts to Aboriginal or treaty rights in relation to proposed IRP Plans (which may include the individual IRP Alternatives considered) and Leave to Construct applications. Any concerns can be considered on a case-by-case basis when an IRP Plan or a Leave to Construct application comes before the OEB for approval.

When Enbridge Gas requests approval for an IRP Plan or a Leave to Construct, it will be necessary for Enbridge Gas to follow the requirements in the *Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario* regarding Indigenous consultation, if applicable.

Cost Recovery and Accounting Treatment Principles: Costs associated with IRP can fall into three categories: incremental IRP administrative costs, project costs to implement IRP Alternatives, and ongoing operational and maintenance costs to operate and maintain an IRP Alternative after it has been brought into service. Project costs for IRP Alternatives, similar to the costs for infrastructure builds, will be eligible for inclusion in rate base, where Enbridge Gas owns and operates the IRP Alternative. Until rebasing, the associated revenue requirement of these project costs will be recorded in a capital costs deferral account for recovery annually or at rebasing as requested by Enbridge Gas. Where Enbridge Gas proposes to make an enabling payment to a competitive service provider and does not own or operate the asset, these costs, if approved, will be included in the category of ongoing operational and maintenance costs and recovered as operating expenses. Until rebasing, these operating costs will be recorded in an operating costs deferral account for recovery annually or at rebasing as requested by Enbridge Gas. Incremental IRP administrative costs and other ongoing operational and maintenance costs will also be treated as expenses and recorded in this account.

Future IRP Plan Applications: When Enbridge Gas determines that an IRP Alternative (either alone, in combination with other IRP Alternatives, or in combination with a facility project) is the best option to address a system need, it will apply for approval of an IRP Plan that enables the alternative. The IRP Framework establishes a new OEB approval process for IRP Plans, under section 36 of the *OEB Act*. An IRP Plan approval will endorse the IRP Plan and approve the cost consequences. The OEB expects that an approach to cost allocation will be part of the IRP Plan approval. The costs would then be recovered, subject to a prudence review, through the IRP Costs deferral accounts annually and/or at Enbridge Gas's next rebasing application.

An IRP Plan approval will be mandatory if the forecast costs of the IRP Plan exceed the minimum project cost (currently $2 million, proposed to increase to $10 million) that would necessitate a Leave to Construct approval for a pipeline project. Enbridge Gas is expected to seek approval for an adjustment to an IRP Plan, if any cost adjustment is an increase of greater than 25% of the approved cost. When seeking recovery of actual IRP Plan costs, Enbridge Gas will need to demonstrate that it has been prudent in managing its actions and resulting costs, as is typical for all requests for cost recovery.

Monitoring and Reporting: Enbridge Gas will file an annual IRP report with the OEB as part of its annual Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application, with information that includes updates on IRP pilots, potential and approved IRP Plans, and the most recent results of its IRP Assessment Process for system needs, including reporting on those system needs where the assessment ruled out further consideration of IRP Alternatives. The OEB does not intend to approve the annual IRP report, but it could impact the OEB's findings on recovery of the costs in the IRP Costs deferral accounts or inform future proceedings.

IRP Costs Deferral Accounts: The OEB is establishing two IRP Costs deferral accounts for the period from 2021 to 2023, to track incremental IRP-related costs not included in Enbridge Gas's base rates. Enbridge Gas may request disposition of the balances in these accounts, when eligible, as part of its annual Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application.

IRP Pilot Projects: The OEB expects that two IRP pilot projects will be selected and deployed by the end of 2022 as proposed by Enbridge Gas. The pilots are expected to assist in understanding and evaluating how IRP can be implemented to avoid, delay or reduce facility projects. The detailed consideration of IRP pilot projects should commence shortly after the issuance of the IRP Framework with input being sought from the IRP Technical Working Group. The implementation of pilots should not be a barrier to addressing a system need through a non-pilot IRP Plan, if an exceptional time-limited opportunity arises prior to the completion of the pilots.

Advanced Metering Infrastructure: The OEB concludes that there is insufficient information to determine if advanced metering infrastructure is a cost-effective enabler of IRP.

2 THE PROCESS

Enbridge Gas Inc. (Enbridge Gas) originally submitted an Integrated Resource Planning (IRP) proposal to the OEB on November 1, 2019 as part of its Dawn-Parkway System Expansion Project Application (EB-2019-0159).

On April 28, 2020, the OEB issued a Notice of Hearing that initiated a review of Enbridge Gas's IRP proposal as a separate proceeding (EB-2020-0091).

On May 21, 2020, the OEB issued Procedural Order No. 1 that granted intervenor status and cost eligibility, and provided a draft issues list for comment.

The following parties applied for and were granted intervenor status:

- Anwaatin Inc. (Anwaatin)
- Association of Power Producers of Ontario (APPRO)
- Building Owners and Managers Association, Greater Toronto (BOMA)
- Canadian Manufacturers & Exporters (CME)
- The City of Hamilton
- Consumers Council of Canada (CCC)
- Energy Probe Research Foundation (Energy Probe)
- Environmental Defence (ED)
- EPCOR Natural Gas Limited Partnership (ENGLP)
- Federation of Rental-housing Providers of Ontario (FRPO)
- Green Energy Coalition (GEC)
- Independent Electricity System Operator (IESO)
- Industrial Gas Users Association (IGUA)
- London Property Management Association (LPMA)
- Low-Income Energy Network (LIEN)
- Ontario Greenhouse Vegetable Growers (OGVG)
- Ontario Sustainable Energy Association (OSEA)
- Pollution Probe
- School Energy Coalition (SEC)
- The Corporation of the City of Kitchener – Utilities Division (City of Kitchener)
- TransCanada Pipelines Limited (TCPL)
- Vulnerable Energy Consumers Coalition (VECC)

Anwaatin, APPRO, BOMA, CCC, CME, Energy Probe, Environmental Defence, FRPO, GEC, IGUA, LIEN, LPMA, OGVG, OSEA, Pollution Probe, SEC and VECC also applied for and were granted cost eligibility.

On July 15, 2020, the OEB issued a Decision on Issues List and Procedural Order No. 2 that approved a final Issues List, and included provisions for Enbridge Gas and other parties regarding filing additional evidence. On July 22, 2020, Enbridge Gas filed an IRP Study prepared by ICF Canada in support of its application.[1]

In Procedural Order No. 4, issued August 20, 2020, the OEB accepted proposals to file additional evidence submitted by Enbridge Gas, OEB staff, and GEC/ED. In Procedural Order No. 5, issued September 15, 2020, the OEB denied FRPO's proposal to file evidence on supply-side IRP Alternatives, but indicated that supply-side alternatives were in scope of the proceeding, and questions regarding their treatment in the IRP proposal could be put to Enbridge Gas through the interrogatory process.

On October 15, 2020, Enbridge Gas filed additional evidence regarding its IRP proposal, which also included an updated jurisdictional review by ICF Canada of advances of natural gas IRP in other jurisdictions since the completion of the original IRP Study.[2]

The evidence of OEB staff and GEC/ED was filed on November 12, 2020 (the Guidehouse report)[3] and November 23, 2020 (the EFG {Energy Futures Group} report)[4], respectively. The Guidehouse report assessed the IRP experience of natural gas utilities in New York State and its relevance to Ontario. The EFG report made recommendations for IRP in Ontario based on lessons learned from the electricity sector, jurisdictions other than New York State, and natural gas demand-side management programs. Enbridge Gas filed responding evidence regarding these reports on December 11, 2020.

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[1] *Natural Gas Integrated Resource Planning: Initial Assessment of the Potential to Employ Targeted DSM to Influence Future Natural Gas Infrastructure Investment*, ICF Canada, May 18, 2018
[2] *IRP Jurisdictional Review Report*, ICF Canada, October 14, 2020
[3] *Natural Gas Integrated Resource Planning in New York State and Ontario*, Guidehouse Inc., November 12, 2020
[4] *Best Practices for Gas IRP and Consideration of "Non-Pipe" Alternatives to Traditional Infrastructure Investments*, (Exhibit M2.GEC-ED), Chris Neme, Energy Futures Group, November 23, 2020

Following an interrogatory phase regarding all evidence filed by parties, the OEB held a series of transcribed virtual events in this proceeding, including a Technical Conference on February 10-12, 2021, a Presentation Day on February 19, 2021, and an Oral Hearing on March 1-4, 2021.

Enbridge Gas filed its Argument-in-Chief on March 17, 2021. Intervenors and OEB staff filed final arguments on or before March 31, 2021. All intervenors filed final arguments with the exception of ENGLP, the City of Hamilton, the City of Kitchener, the IESO, and TCPL. Two letters of comment were also received, from Diverso Energy and the Ontario Geothermal Association. Enbridge Gas filed its reply argument on April 21, 2021.

3 APPLICATION SUMMARY

Enbridge Gas originally requested that the OEB determine that the policy direction set out within its IRP proposal is reasonable and appropriate.[5]

In its Argument-in-Chief, Enbridge Gas clarified that it is requesting that the OEB approve an IRP Framework for Enbridge Gas that includes each of the following items:[6]

1) **Guiding Principles**: Approval of Reliability and Safety, Cost Effectiveness, Public Policy and Optimized Scoping as appropriate guiding principles to inform and influence how Enbridge Gas implements IRP.
2) **IRP Proposal Elements**:
   a) **Types of IRPAs**: Approval for Enbridge Gas to use a wide variety of demand side alternatives (gas and non-gas, including electricity-based solutions), along with appropriate supply side alternatives, to meet an identified need/constraint (including allowing for consideration of a variety of ownership, operation and/or procurement scenarios for each).
   b) **IRP Assessment Process:** Approval of a prescribed process, consisting of the four steps described below, to determine whether to pursue IRP solutions for an identified need/constraint.
      i) *Identification of Constraints*: Enbridge Gas's asset management process will identify potential system needs/constraints up to ten years in the future and describe these in annual updates to the Asset Management Plan (AMP).
      ii) *Binary Screening Criteria:* Enbridge Gas will apply five binary screening criteria to identified system needs/constraints in the AMP to determine whether further IRP evaluation is appropriate.
      iii) *Two-Stage Evaluation Process:* Where a project progresses past the initial binary screening, Enbridge Gas will determine whether to proceed with an IRP Plan through two stages. First, Enbridge Gas will determine whether potential IRPAs could meet the identified constraint need. If yes, then Enbridge Gas will compare one or more IRP Plans to the baseline Facility Alternative, using a DCF+ {Discounted Cash Flow +} test, to determine the optimum alternative.
      iv) *Periodic Review:* Where circumstances change (for example, the nature or timing of an identified need/constraint alters materially, or significant policy changes are announced by government or the OEB), then Enbridge Gas will

[5] Exhibit A, Tab 13, p. 1
[6] Argument-in-Chief, pp. 13-15

review its IRP determinations related to identified needs/constraints (reflecting changes through the annual update to the AMP) and will report to the OEB, stakeholders and potentially affected Indigenous groups as appropriate (either through the AMP, the IRP Report or via an IRPA application).

c) **Stakeholder Outreach and Engagement Process:** Approval of the proposed three-component stakeholdering process, including a purpose-specific stakeholder Technical Working Group to support IRPA development and to identify and discuss new IRP solutions and IRP avoided costs and benefits.
d) **IRPA Cost Recovery and Accounting Treatment Fundamentals:** Approval of like-for-like treatment of IRPA investments, such that longer term investments in IRPA Plans will be capitalized as rate base, with cost recovery similar to the facility investments that they are replacing at the time of in-service (with IRPA costs amortized over their useful lives).
e) **Future IRP Plan Applications:** Approval of a process similar to the Leave to Construct approval process, to review and approve a proposed IRP Plan designed to meet an identified need/constraint, with Enbridge Gas being given flexibility to adjust the IRP Plan without further OEB review except where the costs being adjusted are an increase of 25% or greater of the total approved cost.
f) **Monitoring and Reporting:** Approval of the proposed annual IRP reporting from Enbridge Gas that will address IRP integration into existing planning processes, IRPA effectiveness, IRP pilot projects planned or underway, IRP stakeholdering and IRPA implementation.

3) **IRP Costs Deferral Account:** Approval of an IRP Costs deferral account which will track all incremental IRP-related costs not included in base rates (capital, operating and administrative costs) during the current deferred rebasing term.
4) **IRP Pilot Project Proposal:** Approval for Enbridge Gas to develop two pilot projects to be developed and initiated by the end of 2022 – one of which will apply the new IRP Framework through development and implementation of an IRP Plan to meet an identified need/constraint and the other of which will test a promising IRPA such as Demand Response, along with Advanced Metering Infrastructure (AMI), if possible.
5) **AMI Acknowledgement:** An indication of the OEB’s support for the role of AMI as an important enabler of successful IRP and IRPAs.

4 STRUCTURE OF THE DECISION

The Decision and Order follows the format of Enbridge Gas's Argument-in-Chief, and the specific approvals requested by Enbridge Gas as part of the IRP Framework. In addition, the Decision and Order includes two chapters on issues that are relevant to the IRP Framework but do not address specific approvals requested by Enbridge Gas, regarding Indigenous engagement and consultation, and IRP-related risk. Appendix A provides the approved first-generation IRP Framework, consistent with the findings in the Decision and Order.

5 IRP FRAMEWORK AND DEFINITION OF IRP

This chapter discusses the need for, and form of, an Integrated Resource Planning (IRP) Framework for Enbridge Gas, and the definition of IRP within such a Framework.

Within the energy sector generally, integrated resource planning usually refers to a planning process that evaluates and compares both supply-side and demand-side options for meeting an energy system need, and may also refer to consideration of multiple energy sources, and co-ordination or integration between multiple energy service providers.

In the context of Enbridge Gas's operations, prior to Enbridge Gas's IRP application, the OEB had previously considered the role of both supply-side and demand-side options for meeting the system needs of Enbridge Gas (and its predecessors, Enbridge Gas Distribution and Union Gas), and more specifically the potential for natural gas demand-side management (DSM) to defer or avoid capital investments in natural gas infrastructure, in several Leave to Construct decisions, and in the OEB's oversight of natural gas DSM. The following table provides examples of these previous considerations.

Table 1: Previous OEB Consideration of Integrated Resource Planning For Enbridge Gas

Date	Initiative	Proceeding
January 30, 2014	OEB issues Decision and Order on GTA-Parkway Project, which concludes that further examination of natural gas IRP is warranted, and provides guidance regarding assessment of demand-side alternatives in Leave to Construct applications	EB-2012-0451 EB-2012-0433 EB-2013-0074
December 22, 2014	OEB issues 2015-2020 DSM Framework, which includes infrastructure deferral as one of the goals of DSM	EB-2014-0134
January 20, 2016	OEB issues Decision and Order on EGD/Union 2015-2020 DSM plans, which directs EGD and Union to work jointly on a transition plan that outlines how to include DSM as part of future infrastructure planning activities	EB-2015-0029 EB-2015-0049

January 15, 2018	Enbridge Gas Distribution files IRP transition plan, and study from ICF Canada, as part of mid-term review of DSM framework	EB-2017-0127 EB-2017-0128
November 29, 2018	OEB issues report on mid-term review of DSM framework, which indicates that natural gas utilities should include a comprehensive evaluation of conservation and energy efficiency as an alternative to reduce or defer infrastructure investments as part of all leave to construct applications	EB-2017-0127 EB-2017-0128
January 3, 2019	OEB issues Decision and Order on EGD's Bathurst Reinforcement Leave to Construct application, finding that EGD's process for considering DSM as a viable alternative to this Project was not appropriate	EB-2018-0097
November 1, 2019	Enbridge Gas files IRP proposal as part of Dawn-Parkway Expansion Leave to Construct Application	EB-2019-0159

Enbridge Gas indicated that it filed its original IRP proposal for three reasons:[7]

1) To be responsive to recent direction from the OEB to: (a) consider demand-side management (DSM) as a pipeline alternative at the preliminary stage of project development in the context of leave to construct applications, (b) develop more rigorous, robust and comprehensive procedures to ensure conservation and energy efficiency opportunities can be reasonably considered as alternatives to future capital projects, as requested by the OEB in its Report on the DSM Mid-Term Review.[8]

2) To establish the necessary IRP policy guidance required for Enbridge Gas to be successful in considering IRP Alternatives (IRPAs) as non-facility alternatives to future expansion/reinforcement projects effectively and efficiently.

3) To demonstrate that IRP was not a viable alternative to the proposed Dawn-Parkway

[7] Exhibit A, Tab 13, p. 2
[8] *Report of the Ontario Energy Board - Mid-Term Review of the DSM Framework for Natural Gas Distributors (2015-2020)*, November 29, 2018, pp. 20-21

System Expansion project.

Enbridge Gas's application for the proposed Dawn-Parkway System Expansion project has been withdrawn and is no longer before the OEB.[9] However, the first two reasons noted by Enbridge Gas for considering Enbridge Gas's IRP proposal remain relevant to the current application.

Need for, and Form of, IRP Framework

In its original application, Enbridge Gas requested that the OEB determine that the policy direction set out within its IRP proposal is reasonable and appropriate.[10] In its Argument-in-Chief, Enbridge Gas requested that, "as part of the IRP Framework that will be issued by the OEB", the OEB consider and approve specific elements of its proposal.[11]

Several parties (FRPO, OEB staff, Pollution Probe, SEC) argued that consideration of different options to meet system needs is already an obligatory activity for Enbridge Gas, regardless of whether there is an IRP Framework in place, although a Framework may provide more detail on specific aspects.

However, most parties (including those above except for SEC) agreed that an IRP Framework was desirable to guide Enbridge Gas's consideration of alternatives in system planning.

Parties generally used Enbridge's IRP proposal as the starting point to frame their submissions regarding the content of the IRP Framework, with varying degrees of differentiation from Enbridge's IRP proposal. Only SEC argued that Enbridge's IRP proposal should be rejected outright;[12] however, SEC proposed an alternative approach to IRP, not a rejection of the principle that Enbridge Gas needs to consider different options to meeting system needs.

There was a range of views as to how detailed an IRP Framework should be. Energy Probe and Pollution Probe argued that more detail was needed, but other parties (LPMA, SEC) expressed caution about overly pre-determining or constraining Enbridge Gas's approach to IRP, in the absence of specific IRPAs or a system plan developed with consideration of IRPAs in mind. OEB staff recommended that the IRP Framework

9 EB-2019-0159, Procedural Order No. 8, November 18, 2020
10 Exhibit A, Tab 13, p. 1
11 Argument-in-Chief, pp. 12-15
12 SEC Argument, p. 8

be high-level in nature, to recognize that the details of Enbridge Gas's approach to IRP will evolve based on the learnings acquired in the initial years of the Framework. OGVG suggested that the OEB make clear that the development of an IRP Framework is expected to be an iterative process.

Definition and Scope of IRP for Enbridge Gas

As part of its Argument-in-Chief, Enbridge Gas proposed two potential definitions of IRP as it would apply to Enbridge Gas, that could be adopted for the IRP Framework as follows:[13]

- IRP is a multi-faceted planning process that includes the identification, evaluation and implementation of realistic natural gas supply-side and demand-side options (including the interplay of these options) to determine the solution to an identified future need or constraint that provides the best combination of cost and risk for Enbridge Gas customers.
- IRP is aimed at considering facility and non-facility alternatives to address long-term system constraints/needs such that an optimized and economic solution is proposed and implemented to meet the identified constraint or need.

While there are minor differences between these proposed definitions, both frame IRP as a planning process driven by the system needs of Enbridge Gas's operations, considering different options to meet these system needs, and determining the best approach to meet these needs.

OEB staff proposed a similar definition:

> Integrated Resource Planning is a planning strategy and process that considers facility and non-facility alternatives (including the interplay of these options) to address the system needs of Enbridge Gas's regulated operations, and identifies and implements the alternative (or combination of alternatives) that is in the best interest of Enbridge Gas and its customers, taking into account reliability and safety, cost-effectiveness, risk minimization, planning and regulatory efficiency, stakeholder perspectives, and alignment with public policy objectives.[14]

Most parties accepted Enbridge Gas's definition or proposed similar definitions.

[13] Argument-in-Chief, p. 6
[14] OEB Staff argument, p. 15

One area where parties' views differed was whether the scope and definition of IRP should be limited to Enbridge Gas's operations or should require more integrated energy planning with other energy providers.

Parties such as OGVG, Energy Probe and IGUA argued that the IRP Framework should be drafted and scoped with regards to the OEB's legislated objectives for natural gas[15] and the OEB's responsibilities under the OEB Act for regulation and oversight of natural gas distribution, transmission, and storage. Energy Probe submitted that consideration of broad energy planning is a policy issue for the Ontario government to consider and provide direction to the OEB and Enbridge Gas as necessary.

Other parties argued that this framing was too narrow in scope, both in the context of an expected energy transition to lower-carbon energy sources in the coming years, and a desire to meet Ontario's energy needs in the most efficient way possible. LPMA proposed a definition for IRP as an "energy sector wide planning process that evaluates and compares all available energy demand-side and supply-side options."[16], which would extend to maximizing the utilization of both natural gas and electricity assets, as part of the energy transition.

FRPO objected to Enbridge Gas's reference to "long-term system constraints/needs" within its definition of IRP, submitting that IRP can also encompass bridging mechanisms that are short- and medium-term solutions. Pollution Probe also defined IRP as being inclusive of short- and medium-term planning decisions.

Findings

The OEB acknowledges and thanks the many parties who participated in this proceeding. The parties provided diverse perspectives as to how to proceed with the development of alternatives to infrastructure builds. The studies by ICF Canada, Energy Futures Group and Guidehouse assisted the OEB in understanding the progress of IRP in other jurisdictions, and were taken into consideration in developing the IRP Framework. IRP in the natural gas sector has been initiated in only a few jurisdictions, and where work is underway it appears to still be in early stages.

[15] OEB Act, s.2
[16] LPMA Argument, p. 2

Need for, and Form of, IRP Framework

Some parties submitted that it was premature to develop an IRP Framework, while others suggested that a detailed and comprehensive IRP Framework would allow for more efficient developments to replace infrastructure construction. The OEB has concluded that given the direction in many OEB decisions over the years requiring Enbridge Gas to undertake a more thorough consideration of alternatives, the OEB must provide direction on the approvals Enbridge Gas requested and respond to the issues raised by several parties, in an IRP Framework. The OEB is establishing a first-generation IRP Framework with the expectation that enhancements and improvements will be made in the future on the basis of the experience gained in Ontario with pilot projects and other IRP activities, drawing on successes achieved in other jurisdictions, and future policy direction. A first-generation IRP Framework including applicable definitions is provided in Appendix A. The Framework is a companion document to this Decision and Order regarding IRP for Enbridge Gas.

The IRP Framework provides direction to Enbridge Gas on topics to be covered in an IRP Plan and the OEB's requirements as Enbridge Gas considers and develops IRP Plans to meet its system needs. If Enbridge Gas has reasons for a specific IRP Plan to deviate from the Framework, it should justify why deviations from the Framework requirements are appropriate.

The IRP Framework has been established for Enbridge Gas; however, it should also be used as a resource to guide EPCOR Natural Gas Limited Partnership (ENGLP) when it examines infrastructure investments and potential alternatives. The OEB expects that this IRP Framework for Enbridge Gas will be a starting point for consideration of an IRP Framework that would be appropriate for ENGLP.

How the IRP Framework will address the specific elements of Enbridge Gas's IRP proposal is discussed in subsequent chapters of this Decision and Order.

Definition and Scope of IRP for Enbridge Gas

The OEB finds that the OEB staff definition of IRP is a generally sound basis on which to develop this first-generation IRP Framework.

The OEB is establishing the following definition of IRP.

> Integrated Resource Planning is a planning strategy and process that considers Facility Alternatives and IRP Alternatives (including the interplay of these options) to address the system needs of Enbridge Gas's regulated operations and identifies and implements the alternative (or combination of alternatives) that is in the best interest of Enbridge Gas and its customers, taking into account reliability and safety, cost-effectiveness, public policy, optimized scoping, and risk management.

Some parties suggested that IRP should be focused on energy requirements and not just natural gas. The OEB agrees with Enbridge Gas that this first-generation IRP Framework should focus on the needs of its natural gas customers. Natural gas investment planning is already very complex, and it is premature to attempt to move to integrated energy planning or attempt to anticipate the future energy transition. Work is underway on an update to Ontario's long-term energy planning framework[17] which might provide policy direction regarding the integration of gas and electricity in assessing energy options.

The OEB has established other definitions which are necessary to the IRP Framework. These are similar to the definitions used by the OEB in its Decision on Issues List and Procedural Order No. 2,[18] but have been updated to be consistent with the details of the final IRP Framework.

- **IRP Assessment Process:** The process used by Enbridge Gas to determine the preferred solution to meet specific system needs, including consideration of Facility Alternatives and IRP Alternatives.

- **Facility Alternative:** A potential infrastructure solution considered under the IRP Assessment Process in response to a specific system need of Enbridge Gas. In this IRP Framework, the term is synonymous with a traditional or conventional facility project. This would typically include a hydrocarbon line (as defined in the *OEB Act*) developed by Enbridge Gas, and ancillary infrastructure. Facility Alternatives determined by Enbridge Gas to be the preferred solution to meet the system need will often require approval from the OEB through a Leave to Construct application. For clarity, non-traditional solutions to system needs that include infrastructure developed by Enbridge Gas, such as injection of

[17] Environmental Registry notice ERO 019-3007, January 27, 2021
[18] Decision on Issues List and Procedural Order No.2, July 15, 2020, p. 6

compressed or renewable natural gas, or storage of natural gas within the distribution or transmission system, are considered to be IRP Alternatives and not Facility Alternatives.

- **IRP Alternative (IRPA):** A potential solution other than a Facility Alternative considered in Enbridge Gas's IRP Assessment Process in response to a specific system need of Enbridge Gas. IRPAs determined by Enbridge Gas to be the preferred solution to meet the system need (alone, in combination with other IRPAs, or in combination with a Facility Alternative) would likely be brought forward for approval from the OEB through an IRP Plan.
- **IRP Plan:** A plan filed by Enbridge Gas for OEB approval in response to a specific system need, that includes one or more IRPAs.

6 GUIDING PRINCIPLES

Enbridge Gas requested "approval of reliability and safety, cost effectiveness, public policy and optimized scoping as appropriate guiding principles to inform and influence how Enbridge Gas implements IRP."[19]

Enbridge Gas indicated that approved guiding principles for IRP would be valuable in providing direction and guidance in the implementation of IRP Plans, and in determining how to deal with unforeseen items. Enbridge Gas submitted that, individually and collectively, its proposed guiding principles were consistent with the OEB's statutory objectives in relation to natural gas.[20]

Specific Guiding Principles

Enbridge Gas proposed the following wording for these guiding principles[21]:

- Reliability and Safety - In considering IRPAs as part of system planning processes, Enbridge Gas's system design principles cannot be compromised, and the reliable and safe delivery of firm contracted peak period natural gas volumes to Enbridge Gas's customers must remain of paramount importance.
- Cost Effectiveness – IRPAs must be cost-effective (competitive) compared to other facility and non-facility alternatives, including taking into account impacts on Enbridge Gas ratepayers.
- Public Policy – IRP will be considered in a manner to ensure that it is supportive of and aligned with public policy, where appropriate.
- Optimized Scoping - Recognizing that reviewing IRPAs for every forecasted infrastructure project would be extremely time intensive, binary screening should be undertaken to confirm which forecast need(s) should undergo an IRP assessment and to ensure a focus at the outset on efficient and effective IRPA investment.

Most parties commenting on this issue agreed with the importance of establishing guiding principles for the IRP Framework, with the exception of Pollution Probe.[22]

[19] Argument-in-Chief, p. 13
[20] OEB Act, s.2
[21] Argument-in-Chief, p. 6
[22] Pollution Probe recommended the guiding principles be rejected in favour of establishing foundational objectives of increased accountability, increased transparency and performance measurement.

Commenting parties supported the proposed guiding principles on reliability and safety,[23] and on cost-effectiveness.

On the proposed guiding principle on public policy, CME submitted that the relevant public policy goals should be taken from the OEB's statutory objectives, a position which was supported by Enbridge Gas. GEC suggested rewording this guiding principle to require "Alignment with other governmental policy objectives", which Enbridge Gas did not support, stating that this could lead to confusion as to what "other" government policies are relevant, and which are paramount.[24]

Parties expressed some concerns with Enbridge Gas's proposed guiding principle on optimized scoping. Parties generally agreed that some form of scoping was necessary, but expressed concerns regarding how this principle might be applied in practice to unduly screen out potential IRPAs.

OEB staff proposed to broaden and modify the optimized scoping guiding principle to:

- Planning and Regulatory Efficiency - To focus on efficient and effective IRPA investment, resources are allocated to IRP activities in proportion to their expected impact, at all steps of IRP.

In addition to the guiding principles proposed by Enbridge Gas, several parties proposed additional guiding principles.

OEB staff and GEC both proposed a principle on risk minimization, which included minimizing the economic risk associated with meeting system needs and reliability requirements.[25] OEB staff's proposed principle also indicated that risks and rewards are to be allocated appropriately between Enbridge Gas and its customers.

OEB staff proposed a new principle on stakeholder perspectives, such that "IRP takes into consideration the perspectives of stakeholders regarding how best to meet system needs, including the perspectives of stakeholders and potentially affected Indigenous groups from the specific geographic area relevant to a system need".

FRPO proposed a guiding principle regarding procedural fairness and reasonableness, to ensure evaluation of IRPAs was conducted on a level playing field, which could

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[23] FRPO supported the proposed guiding principle of reliability and safety, but expressed concern that this should not be used selectively to bias utility ownership of assets over reliable third-party assets.
[24] Enbridge Gas Reply Argument, p. 26
[25] GEC's proposed principle also noted reliability risk.

include stakeholders seeking the OEB's assistance to obtain information from Enbridge Gas if required. Enbridge Gas expressed concern that unencumbered access to any and all utility information would lead to additional regulatory burden.

Finally, GEC proposed three additional guiding principles: "equitable consideration of all viable resource options", "alignment of utility interests with IRP goals" and "timely and accountable assessment of alternatives".

Findings

The OEB approves the adoption of guiding principles for the IRP Framework on reliability and safety, cost-effectiveness, public policy, optimized scoping, and risk management. These principles are consistent with the OEB's statutory objectives for natural gas.

The OEB has determined that guiding principles are essential to the establishment of a robust IRP Framework. The IRP Framework cannot anticipate all situations that might occur in the consideration of alternatives to infrastructure builds. The guiding principles will assist in consistent direction for IRP, particularly in these early years. Similarly, Enbridge's Gas Supply Plan is underpinned by guiding principles that inform the creation and assessment of that plan. IRP Plans filed with the OEB should include a section to discuss how these guiding principles have been addressed.

The OEB concludes that there is widespread support for the guiding principles that address reliability/safety and cost effectiveness.

The OEB finds that the guiding principle for public policy should be driven by the OEB's statutory objectives and provincial and federal laws and regulations. While Enbridge Gas and the OEB may also consider other relevant provincial and federal policies, it is acknowledged that the OEB's statutory objectives must have primacy in the event of any conflict with such policies.

The OEB concludes that it is appropriate to include Enbridge Gas's proposed optimized scoping principle in the guiding principles. The optimized scoping principle is directed to establishing an efficient process, which the OEB agrees is essential particularly at this early stage of implementation. Further discussion of concerns regarding how Enbridge Gas will apply this principle in practice will be addressed in section 8.2 ("Binary Screening Criteria"). The addition of effectiveness proposed by OEB staff can be covered under the guiding principle on cost-effectiveness.

OEB staff and GEC proposed to add a guiding principle on risk minimization. Concern was raised by Enbridge Gas that the risk of IRPAs can be materially different from the risk of an infrastructure build. With experience in implementing IRPAs, Enbridge Gas will be better equipped to assess the risk and to take mitigating actions for IRPAs. The issue of who should bear the risk also received considerable attention. At a strategic level, the OEB recognizes the IRPAs could have different risk profiles and concludes that it is appropriate for the IRP Framework to include a principle on risk management, similar to the risk minimization principle proposed by OEB staff:

- Risk management - Economic risks associated with both Facility Alternatives and IRPAs in meeting system needs are evaluated and appropriately mitigated. Risks and rewards are allocated appropriately between Enbridge Gas and its customers.

The allocation of IRP risks is discussed in chapter 9 (“Allocation of IRP Risks”). Aside from this principle on risk management, the OEB has determined that additional guiding principles proposed by OEB staff, FRPO, and GEC are not required.

OEB staff proposed to add a guiding principle on stakeholder perspectives. The OEB considers stakeholdering an important element of the IRP process. However, it does not require a separate guiding principle.

Regarding FRPO’s proposed guiding principle on procedural fairness and reasonableness, the IRP Framework must ensure that stakeholders have an opportunity to participate in an effective manner. Therefore, this proposed guiding principle is not required.

Regarding the three additional principles proposed by GEC, the OEB finds that while these are all relevant considerations, they are best handled as part of specific elements of the IRP Framework rather than being established as guiding principles. These topics will be considered further when the proposed elements of the IRP Framework are discussed.

The final guiding principles are as follows:

- Reliability and safety – In considering IRPAs as part of system planning processes, Enbridge Gas’s system design principles cannot be compromised, and the reliable and safe delivery of firm contracted peak period natural gas volumes to Enbridge Gas’s customers must remain of paramount importance.

- Cost-effectiveness – IRPAs must be cost-effective (competitive) compared to Facility Alternatives and other IRPAs, including taking into account impacts on Enbridge Gas customers.

- Public policy – IRP will be considered in a manner to ensure that it is supportive of and aligned with public policy, and in particular the OEB's statutory objectives for the natural gas sector.

- Optimized scoping – Recognizing that reviewing IRPAs for every forecast infrastructure project would be extremely time intensive, binary screening should be undertaken, to confirm which forecast need(s) should undergo evaluation of IRPAs, and to ensure a focus at the outset on efficient and effective IRPA investment.

- Risk management – Economic risks associated with both Facility Alternatives and IRPAs in meeting system needs are evaluated and appropriately mitigated. Risks and rewards are allocated appropriately between Enbridge Gas and its customers.

7 TYPES OF IRPAS

Enbridge Gas requested approval for Enbridge Gas to use a wide variety of IRPAs to meet an identified need/constraint (including allowing for consideration of a variety of ownership, operation and/or procurement scenarios).[26]

The range of IRPAs Enbridge Gas proposed[27] included gas supply-side alternatives (such as compressed natural gas and renewable natural gas, and commercial or market-based alternatives such as peaking supply, third-party assignments, or exchanges), demand-side alternatives (demand response and targeted energy efficiency, gas-fired heat pumps), and non-gas alternatives, in particular, electricity (e.g. geothermal, electric heat pumps) and potentially district energy and power-to-gas. All of these have the potential to address system needs by reducing peak demand in constrained areas of the natural gas distribution or transmission system.

Demand-side IRPAs:

In its initial IRP proposal, Enbridge Gas submitted that IRP should be reviewed and treated separately from its DSM Plan, although Enbridge Gas did not request a specific approval on this topic as part of its Argument-in-Chief in this IRP proceeding. The impact of activity in Enbridge Gas's DSM Plans is already incorporated into Enbridge Gas's demand forecasts, which then informs identification of system needs; however, Enbridge Gas indicated that active use of demand-side solutions in the context of infrastructure planning should be done through the IRP Framework, not the DSM Plan. In a letter dated December 1, 2020, the OEB invited Enbridge Gas to file a new multi-year DSM plan for the post-2021 period. This letter indicated that the OEB would decide on the relationship between the IRP Framework and utility DSM plans in this IRP proceeding, including the extent to which Enbridge Gas will be expected to meet the objective of creating opportunities to actively defer or avoid infrastructure projects within its DSM plan.[28] Subsequently, Enbridge Gas has filed an application for its next DSM Plan (2022 to 2027), which is currently before the OEB and does not include any geotargeted energy efficiency programming, pending any direction arising from the IRP Framework.[29]

[26] Argument-in-Chief, p. 16
[27] Exhibit B, pp. 21-29, Argument-in-Chief, p. 18
[28] OEB Letter, Re: Post-2020 Natural Gas Demand Side Management Framework, December 1, 2020
[29] Multi-Year Demand Side Management Plan (2022 to 2027), EB-2021-0002, Application and Evidence, Exhibit C, Tab 1, Schedule 2

Within the IRP Framework, Enbridge Gas proposed that demand-side solutions considered as IRPAs could include enhanced targeted energy efficiency programs and demand response programs. Enhanced targeted energy efficiency programs would focus on achieving a high penetration in a specific geographical area to reduce peak period system demands. This could include supplemental targeted funding or incentives to customers in constrained areas for existing energy efficiency programs that are already offered franchise-wide through the DSM Plan, or entirely new energy efficiency programs, including efficiency measures such as gas-fired heat pumps.

Demand response programs are designed to incent or oblige the customer to reduce or shift energy usage during peak periods. They can be controlled by the utility or the customer and can be voluntary or contractually binding. Demand response programs are well-established in the electricity sector, and natural gas demand response programs are being undertaken by utilities pursuing IRP in New York State.

Somewhat similar in nature to demand response programs are interruptible rates. Customers on interruptible rates pay a lower rate in exchange for the ability of Enbridge Gas to curtail delivery if capacity is not available on the system. Interruptible volumes are not included in Enbridge Gas's design day assumptions. Therefore, increased use of interruptible rates could potentially reduce the amount of firm peak demand Enbridge Gas is obligated to serve, helping address a system need. For this reason, Enbridge Gas indicated that it does consider interruptible rates to be a type of IRPA. Enbridge Gas already offers interruptible rates to its Contract Rate customers (larger commercial, institutional and industrial customers). However, Enbridge noted that customers have been moving away from interruptible rates as they value certainty of supply over cost reduction.

No parties opposed the inclusion of demand-side IRPAs within the IRP Framework.

OEB staff submitted that demand-side IRPAs should receive a high priority in the IRP Framework, and that active deferral or avoidance of specific system needs is appropriate to address within the IRP Framework, not the post-2021 DSM Plan. OEB staff also submitted that storage (throughout Enbridge Gas's transmission and distribution system, or potentially on the customer side), although not explicitly mentioned in Enbridge Gas's list of potential IRPAs, should be considered as a solution to meet system needs.

Several parties (FRPO and OSEA) submitted that Enbridge Gas should consider enhancements to increase adoption of interruptible rates. In reply, Enbridge Gas indicated that it would investigate the drivers for recent declines in the use of interruptible services, and could potentially file revised interruptible and firm seasonal services/rates to make them more attractive to customers as part of its 2024 rebasing application.

Supply-side Gas IRPAs

Enbridge Gas also noted several supply-side natural gas solutions that could be considered as IRPAs and alternatives to pipeline construction. Injection of compressed natural gas into the pipeline system in a constrained area, or renewable natural gas sourced within the constrained area, could be potential alternatives to pipeline construction/expansion to meet a system need.

No parties objected to the consideration of the supply-side solutions proposed by Enbridge Gas. FRPO submitted that more consideration needed to be given to market-based supply-side alternatives and commercial transactions. FRPO submitted that through appropriate contractual arrangements requiring delivery of natural gas to specific points on Enbridge Gas's system, the capability of existing pipeline infrastructure (including non-Enbridge Gas pipelines including the TCPL mainline) could be harnessed to avoid or defer the need for Enbridge Gas to build new pipeline infrastructure.

Non-Gas IRPAs, including Electricity

Enbridge Gas sought approval to use non-gas alternatives, including electricity-based solutions, as IRPAs, and specifically requested confirmation from the OEB as to whether or not non-gas alternatives can be considered. Potential non-gas alternatives could include electric air source heat pumps, geothermal systems, and district energy systems. Enbridge Gas acknowledged that these would be new activities that go beyond gas distribution.

Enbridge Gas noted that it is permitted to undertake a broad range of activities within the utility corporation, where such activities are related to energy conservation, promotion of cleaner energy sources and ground source heat pumps, through its Undertakings to the Lieutenant Governor in Council, as supplemented by Orders in Council issued by the government of Ontario.

The ability for Enbridge Gas to undertake an activity does not necessarily mean that it is considered a rate-regulated activity, which is based on whether the activity is done as part of the sale of natural gas or the transmission, distribution and storage of gas, which requires an OEB order under s. 36 of the OEB Act. For example, in a decision regarding Enbridge Gas's application for a Renewable Natural Gas Enabling Program, the OEB determined that a proposed Renewable Natural Gas Upgrading service was a permitted activity for Enbridge Gas through its Undertakings, but would not be rate-regulated, as it was not done as part of the sale of gas or the transmission, distribution or storage of gas.[30]

Enbridge Gas submitted that, in the context of IRP, these non-gas activities would be directed at providing an alternative to distribution (or transmission or storage) facilities, and should be considered a rate-regulated activity, similar to the infrastructure being delayed or avoided.

Parties differed as to whether Enbridge Gas should be allowed to pursue non-gas activities. Parties such as ED, GEC, LPMA, and Pollution Probe supported broad consideration of IRPAs. ED and GEC specifically supported electric heat pumps, and ED and OEB staff noted that there was some precedent for Enbridge Gas considering fuel switching measures in the context of demand-side management activities in previous DSM Frameworks.

Parties expressing concerns around an expanded scope of IRPAs including non-gas activities (CME, IGUA, OEB staff, OGVG) generally argued that these activities may fall outside of the OEB's authority to set rates for the sale of gas or the transmission, distribution, and storage of gas under section 36 of the OEB Act. These activities could potentially involve disconnecting existing natural gas customers or avoiding the connection of new natural gas customers. Parties argued that this is not the proper role for a regulated gas distributor, and natural gas customers should not pay the costs to connect customers to electricity. OEB staff submitted that some applications of non-gas IRPAs may fall within the definition of section 36, but that this would likely be limited, and should not encompass providing energy services such as electricity to new customers who would not be connecting to Enbridge Gas's natural gas network.

In reply, Enbridge Gas indicated that if it is not permitted to offer non-gas IRPAs to customers who are not gas distribution customers, then this would greatly limit the ability of IRP efforts to respond to system expansion needs, which, by their nature, involve the connection of new customers. If Enbridge Gas is not able to offer non-gas IRPAs to such customers, Enbridge Gas submitted that it is very likely that IRP will not be a feasible alternative to meet the system expansion need.

[30] Decision and Order, Application for the Renewable Natural Gas Enabling Program (EB-2017-0319), October 18, 2018, pp. 10-11

GEC and OGVG suggested that, if the OEB determines that it is not appropriate for Enbridge Gas to offer electricity IRPAs, Enbridge Gas should still be required to include non-gas IRPAs in its assessment of alternatives, and, if the electric alternative is determined to be preferable, Enbridge Gas should be required to work with electricity sector entities (e.g. distributors) to facilitate the IRPA. Enbridge Gas submitted that this went beyond the scope of the proceeding, and is not feasible.

OEB staff indicated that the question of whether an alternative energy solution from a provider other than Enbridge Gas, such as an electricity distributor, was preferable could be addressed indirectly, at least for system expansion projects. This would be done by ensuring that any proposed Enbridge Gas system expansion projects were required to pass the E.B.O. 134/188 economic tests (discussed in section 8.3 (“Two-Stage Evaluation Process”)), including whether the preferred approach is for Enbridge Gas to take no action. With these tests, system reinforcement costs are accounted for and may result in the requirement for customer contributions. OEB staff suggested that in areas with high system reinforcement costs, these provisions may lead potential customers to choose a different energy supply technology instead of connecting to the natural gas distribution network.

Role of Market Providers in Delivering IRPAs

Parties raised concerns about unfair competition with non-regulated providers, particularly if Enbridge Gas was allowed to offer electricity IRPAs such as geothermal or air source heat pumps, and if it was determined that Enbridge Gas would be allowed to capitalize some costs, and receive a regulated rate of return with an associated revenue requirement. This matter is discussed in chapter 12 (" IRPA Cost Recovery and Accounting Treatment Principles”).

Enbridge Gas indicated that, in cases where a demand-side IRPA or an electricity IRPA involves equipment or activities already provided by the competitive market, it would look to this market to assist in providing solutions. For supply-side solutions, Enbridge Gas indicated that its role would depend on the nature of the supply-side solution, but that market-based solutions would be considered.

Short-Term IRPAs

Several parties including FRPO encouraged Enbridge Gas to consider shorter-term solutions to temporarily address a system constraint. Enbridge Gas acknowledged that a “bridging solution” to meet the need on a short-to-medium-term basis might be appropriate. However, Enbridge Gas stressed that a more permanent solution would be needed for the longer term.

Menu/Listing of IRPAs

Several parties, including Energy Probe, FRPO, and OEB staff, indicated that a listing or menu of IRPAs being considered by Enbridge Gas would be useful.

OEB staff suggested that Enbridge Gas should be required to develop and maintain a document on the best available information on IRPAs, filed with Enbridge Gas's annual IRP report. OEB staff suggested that the information provided could include the types of IRPAs, estimates of cost, peak demand savings, status in Ontario, potential role and relevance to Enbridge Gas's system, and learnings from pilot projects and other jurisdictions. OEB staff submitted that this would assist Enbridge Gas and other parties as a starting point for consideration of IRPAs for specific system needs and assist the OEB in its review of Enbridge Gas's consideration of alternatives in Leave to Construct/IRP Plan applications. Enbridge Gas agreed that a proposed record of information on available demand-side IRPAs would be a useful addition to the annual IRP Report; however, Enbridge Gas suggested that supply-side options were too situation-specific to include in the report.

Findings

Enbridge Gas is seeking OEB approval to use a wide variety of demand-side and supply-side IRPAs to meet identified needs/constraints.

Enbridge Gas has considerable experience with implementing demand-side solutions such as energy efficiency programs as part of its DSM Plans; however, the programs and measures in DSM Plans have been focused on reducing overall franchise-wide natural gas use for customers and increasing energy efficiency, rather than directed to targeted peak demand reduction to address system needs.

The OEB agrees that demand-side programming, including geotargeted energy efficiency, and demand response programs, should be part of the IRP Framework. The demand-side IRPAs are expected to target specific constrained areas and (among other objectives) encourage customers to reduce peak consumption. In regard to the December 1, 2020 letter and the relationship between the IRP Framework and DSM Plans, the OEB finds that potential merging of DSM energy efficiency with programs aimed at reducing peak demand to meet system needs is premature. Historically, the programs and measures in DSM Plans have been focused on reducing overall franchise-wide natural gas use for customers and increasing energy efficiency, rather than directed to targeted peak demand reduction to address system needs. The approved IRP Framework will provide opportunities to gain experience on demand-side programming that focuses on reducing peak demand. This experience is needed prior to any effort to merge DSM and IRP programming.

Regarding interruptible rates, ongoing rate design and customer adoption of current rates is part of normal operating process and should not need to be incented through an IRP Plan for Enbridge Gas to make enhancements. The OEB directs Enbridge Gas to study its interruptible rates to determine how they might be modified to increase customer adoption of this alternative service. This initiative is expected to help reduce peak demand, and the study should be filed as part of the next rate rebasing application. While approval of interruptible rates would be considered in a rebasing rate application, the impact of interruptible rates to meet a system need/constraint should be considered in an IRP Plan in combination with demand-side or supply-side alternatives.

Supply-side IRPAs, including market-based supply side alternatives, should also be considered, as should natural gas storage.

The OEB finds all of the above options appropriate to the extent that they are cost-effective, and risk has been evaluated and appropriately mitigated. For both demand side and supply-side IRPAs, the OEB supports Enbridge Gas procuring equipment or activities through the competitive market, where feasible and cost-effective. The OEB has concluded that Enbridge Gas should consider both combination IRP Plans (that may include multiple supply-side or demand-side IRPAs or an IRPA in combination with a Facility Alternative) and bridging solutions in its IRP Assessment Process if the bridging solution provides the best alternative in the near term, while exploring longer term solutions.

Enbridge Gas also proposed non-gas IRPAs, specifically electricity-based alternatives. The OEB has concluded that as part of this first-generation IRP Framework, it is not appropriate to provide funding to Enbridge Gas for electricity IRPAs. This may be an element of IRP that will evolve as energy planning evolves, and as experience is gained with the IRP Framework.

Enbridge Gas can also seek opportunities to work with the IESO or local electricity distributors to facilitate electricity-based energy solutions to address a system need/constraint, as an alternative to IRPAs or facility projects undertaken by Enbridge Gas. However, the OEB is not establishing this as a requirement for Enbridge Gas. While in the longer term, there may be an opportunity to have integrated energy resource planning with the optimal fuel choice between all energy sources, the OEB concludes that this would be an excessively challenging requirement during this first-generation IRP Framework. As discussed in chapter 5 (“IRP Framework and Definition of IRP”), directing integrated energy planning between gas and electricity is premature and remains an aspirational goal. Within the Ontario government’s review of the long-term energy planning framework, approaches to selecting optimal energy choices may be assessed.

The guidance on IRPAs in the IRP Framework is based on broad categories of alternatives. The OEB concludes that a document on best available information for demand-side alternatives would promote more timely development of IRP Plans and directs Enbridge Gas to include a listing in its annual IRP Report. The OEB agrees with Enbridge Gas that supply-side alternatives require case-by-case examination and therefore are not required to be included in the listing.

8 IRP ASSESSMENT PROCESS

Enbridge Gas requested approval of a prescribed process, consisting of the four steps described below, to determine whether to pursue IRPAs for an identified need/ constraint.

1. Identification of Constraints

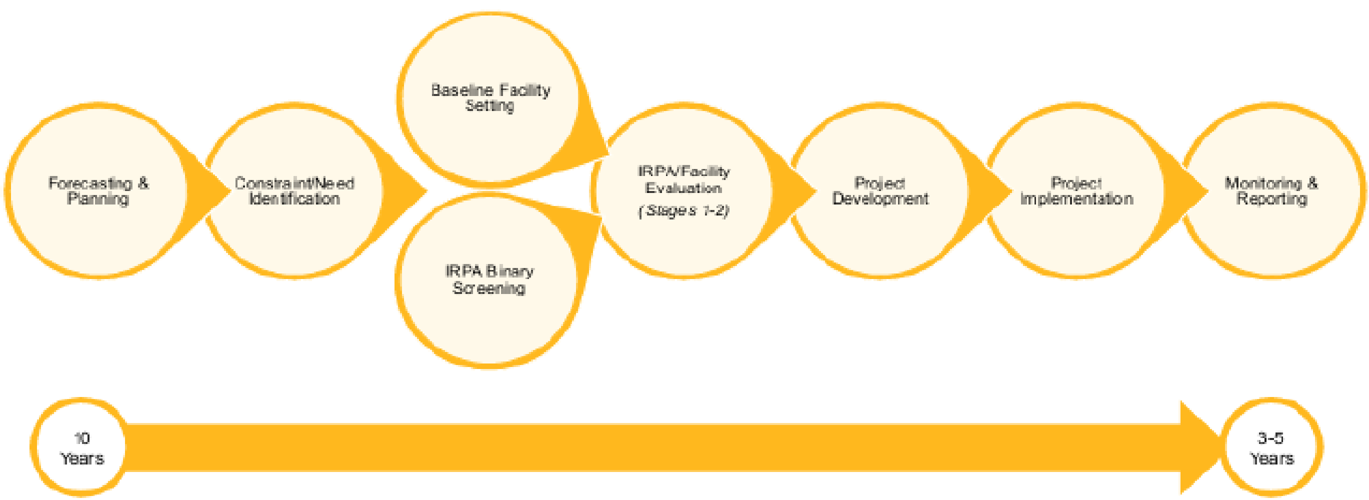
2. Binary Screening Criteria

3. Two-Stage Evaluation Process

4. Periodic Review

Enbridge Gas provided an illustrative process plan describing how it would incorporate its IRP proposal into its existing planning processes, as shown in Figure 1 below.[31]

Figure 1 – Enbridge Gas proposed IRP process



[31] Argument-in-Chief, p. 17

Review of Enbridge Gas's IRP Assessment Determinations

Enbridge Gas indicated that it would use the four-step IRP Assessment Process to determine the best approach to meeting system needs. Enbridge Gas proposed that the OEB would not explicitly oversee or approve Enbridge Gas's determinations in the IRP Assessment Process, until Enbridge Gas brought forward either an application for approval of an IRP Plan or a Leave to Construct application for approval of a facility project.

Several parties agreed with this approach. However, many parties submitted that there should be an opportunity for the OEB and stakeholders to review Enbridge Gas's decisions to not pursue IRP solutions for an identified need/constraint, as a result of its IRP Assessment Process, prior to a project-specific application.

Findings

The OEB is not requiring Enbridge Gas to seek approval for its determinations in the IRP Assessment Process prior to project-specific applications (for an IRP Plan approval or a Leave to Construct approval). In a project-specific application (Leave to Construct or IRP Plan), Enbridge Gas is required to demonstrate that it has followed the IRP Assessment Process, including the results of the analysis at each stage of the process.

However, the OEB is sympathetic to the concerns raised by parties, and has determined the most efficient approach to address this request is to use the annual IRP reporting proposed by Enbridge Gas, discussed in chapter 14 ("Monitoring and Reporting"). Within its annual IRP report, Enbridge Gas is to report on the results of its IRP Assessment Process, including reporting on those system needs where a negative result at step two (binary screening) or step 3 (technical/economic evaluation) resulted in a determination by Enbridge Gas for no further assessment of IRPAs. The IRP Technical Working Group will also be expected to review a draft of Enbridge Gas's annual IRP report, with the review coordinated by OEB staff. Material concerns that remain unresolved within the Technical Working Group will be brought to the attention of the OEB. This process is described in greater detail in chapter 10 ("Stakeholder Outreach and Engagement Process"). The risk that this approach will result in the OEB having no option but to approve a less than optimal project, and who should bear the consequences of this risk, is discussed in chapter 9 ("Allocation of IRP Risks").

8.1 IRP Assessment Process Step 1: Identification of Constraints

Enbridge Gas proposed that its asset management process would identify potential system needs/constraints up to ten years in the future, and describe these in annual updates to the Asset Management Plan (AMP). The AMP is currently filed each year as part of Enbridge Gas's rate adjustment proceedings. The AMP process addresses all utility assets within Enbridge Gas's regulated operations.[32] Under Enbridge Gas's proposal, IRP (and the consideration of IRPAs) would not be triggered by gas supply planning needs. [33]

Enbridge Gas indicated that this ten-year horizon would permit time to consider whether an IRP Plan could meet the identified system needs and, if so, to develop, evaluate and implement an IRP Plan in time to determine whether it is likely to meet the need or constraint.

Enbridge Gas indicated that the consideration of the potential role of IRP Plans for meeting each system need identified during this step, and the current status of IRP Plan consideration, would be documented in Enbridge Gas's AMP. An updated version of this information would be provided each year.[34] Enbridge Gas proposed that the first version of the AMP reflecting this updated process would be filed in Fall 2022.

Parties were generally supportive of Enbridge Gas's proposed approach to identifying system needs/constraints and documenting the current status of consideration of IRP Plans to meet these needs within the AMP on an annual basis. Regarding the scoping of needs identification for the purposes of IRP, OEB staff supported the scoping of IRP to address infrastructure needs, not gas supply planning needs.

OEB staff proposed that the information filed within each AMP should include a list of identified system needs, and for each system need, the status of IRP Plan consideration in regards to meeting the need. This should include the result of the initial binary screening (section 8.2, "Binary Screening Criteria"), and details as to whether and why IRP Plans had been screened out at subsequent steps, with supporting rationale. Enbridge Gas accepted this suggestion.

[32] AMP 2021-2025, section 1.1
[33] Exhibit I. Staff.2
[34] Enbridge Gas's 2021-2025 Asset Management Plan covered a five-year period, but Enbridge Gas has indicated that it will increase the scope of future AMPs back to 10 years, in support of longer-term planning initiatives such as IRP. Exhibit I.Staff.6a

Demand Forecast

Enbridge Gas's demand forecast is a critical input to the AMP and the needs identification process. Peak period demand, and growth in peak period demand, is the main driver of the system needs that are identified in Enbridge Gas's AMP, at least for the types of needs where IRP Plans are likely to be considered.[35]

These system needs are identified based on Enbridge Gas's demand forecast, and in particular, its design day demand forecast, which forecasts Enbridge Gas's requirements in order to meet customer needs on the day of the year with highest demand.

Forecasting design day demand involves many variables, including weather projections, modeling of the annual consumption and temporal demand profile of Enbridge Gas customers, and assumptions regarding any projected increase (or decrease) in the number of Enbridge Gas customers.[36]

Enbridge Gas did not propose any changes to its existing demand forecasting methodology in this proceeding.

Many parties raised concerns with Enbridge Gas's demand forecasting methodology and assumptions; in particular, whether the assumptions in Enbridge Gas's forecast regarding future natural gas demand were consistent with public policy objectives and actions to transition to a lower-carbon energy future. This energy transition is likely to involve reducing greenhouse gas emissions from the energy sector through a combination of lower-carbon energy sources (which could include lower-carbon sources of natural gas or other gaseous fuels such as hydrogen, and alternative energy sources such as electrification) and reduction in energy demand through efficiency and conservation. The role Enbridge Gas will play in this transition, as well as the speed at which this transition will occur, are uncertain.

Parties noted that, if natural gas demand from customers is lower than forecast due to this energy transition, then projected system needs (whether they are to be met by a facility project or an IRP Plan) may not materialize, introducing a risk of stranded or underutilized assets.

[35] Exhibit I.Staff.5(a)
[36] See Enbridge Gas's 5 Year Gas Supply Plan and Exhibit I.4.Staff(a) for more details on Enbridge Gas's demand forecasting methodology.

Environmental Defence and GEC submitted that Enbridge Gas should be directed to consider the potential impacts of decarbonization on gas demand through scenario or sensitivity analysis, and Environmental Defence stated that Enbridge Gas's planning implicitly assumes a 0% probability of declining gas demand. SEC recommended that the OEB require Enbridge Gas to consider stranded asset risk associated with possible declining natural gas demand in its AMP that will be filed in its next rebasing application, primarily through scenario analysis. GEC also submitted that the IRP Framework should require regular assessment of the accuracy of demand forecasts.

Anwaatin recommended that Enbridge Gas take account of the broader policy and regulatory context around greenhouse gas emissions reductions in developing its demand forecast, including the federal government's intent to implement a price on greenhouse gas emissions that will continue to rise to $170/tonne CO_2e by 2030, instead of assuming that the price will remain at $50/tonne CO_2e after 2022. This proposed emissions pricing increase has been announced, but not yet implemented in law, by the Government of Canada.[37] The issue of carbon pricing is also pertinent to cost-effectiveness analysis, discussed in section 8.3 ("Two-Stage Evaluation Process").

In addition to the concerns raised about incorporating decarbonization considerations into demand forecasts, the EFG report filed by GEC/ED suggested that Enbridge Gas's forecast and design day demand inputs may be overly conservative.[38]

OEB staff submitted that the details of the demand forecast methodology do not need to be addressed in the IRP Framework, but did submit that the IRP Framework should require Enbridge Gas to file the supporting ten-year demand forecast that underpins its identification of system constraints, as part of its annual AMP updates. OEB staff also suggested that questions on the demand forecasting methodology could potentially be considered at rebasing, including whether Enbridge Gas's demand forecast is compatible with the existing guidance in the Filing Requirements for Natural Gas Rate Applications.[39]

Enbridge Gas agreed with OEB staff that the demand forecasting methodology could be considered at rebasing, and did not support any of the suggestions from other parties for mandatory changes to the demand forecasting approach as part of the IRP Framework.

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[37] Government of Canada, "A Healthy Environment and a Healthy Economy", p. 26
[38] EFG Report (Exhibit M2.GEC-ED), pp. 35-36
[39] Ontario Energy Board, *Filing Requirement for Natural Gas Rate Applications*, February 16, 2017.

Findings

For this first-generation IRP Framework, the OEB finds the process proposed by Enbridge Gas to identify system constraints or needs is acceptable. Recording potential system needs/constraints up to ten years in the future in the AMP will allow time for a detailed examination of IRPAs. The OEB agrees with Enbridge Gas's proposal that the first version of the AMP reflecting this updated process be filed in Fall 2022.

The OEB directs that the AMP include information about Enbridge Gas's system needs. This includes providing the status of consideration of IRP Plans in regard to meeting system needs, the result of the binary screening, and details on the evaluation. The AMP should also identify any material changes to the demand forecast, relative to the demand forecast that was assessed as part of the most recent rebasing application. As discussed in chapter 14 ("Monitoring and Reporting"), Enbridge Gas will be expected to include relevant information from the AMP, including the most recent results of its IRP Assessment Process for system needs, within its annual IRP report.

The OEB expects that for projects brought to the OEB for approval (both Leave to Construct projects and IRP Plans), the system need will have previously been identified in the AMP (although the preferred project to meet the system need may not have been determined at that time). For any previously unidentified needs, Enbridge Gas will need to provide an explanation as to why the project is needed at this time.

Despite concern raised by some parties about the demand forecast, the OEB has determined that a more comprehensive review of Enbridge Gas's demand forecasting methodology is not needed at this time. Detailed examination of the ten-year demand forecast methodology is appropriately done at Enbridge Gas's next rebasing application, at which time the AMP will be filed as evidence. The OEB also notes that an analysis of the historical accuracy of Enbridge Gas's demand forecast is required by section 2.3.2 of the Filing Requirements for Natural Gas Rate Applications, and thus it is appropriate to file this information at its next rebasing application.

8.2 IRP Assessment Process Step 2: Binary Screening Criteria

Enbridge Gas proposed to apply five binary screening criteria to system needs/constraints identified in the AMP to determine whether further IRP evaluation is appropriate. Enbridge Gas submitted that it is necessary to establish the appropriate scope and scale of system constraints/needs that should qualify for IRP assessment, and that undertaking the full IRP planning process for every forecasted system constraint/need would be a substantial incremental administrative cost burden. Suitable screening criteria would allow IRP efforts to be focused on appropriate projects with the highest likelihood of success. Enbridge Gas also noted that expert evidence filed in this proceeding showed that binary screening is performed in other jurisdictions undertaking gas and electric IRP.

Enbridge Gas indicated that facility expansion/reinforcement projects, where growth is the main driver, will be the area where IRP will be most effectively applied. Enbridge Gas defines facility expansion/reinforcement projects as projects designed to meet system needs arising from the addition of new customers to the system or from the increasing load/demands of existing customers, and are projects that support the transmission and distribution of natural gas at the system level as opposed to projects that are required to connect a specific customer.[40] However, Enbridge Gas indicated that IRP should also be considered for larger pipeline replacement and relocation projects, as there may be opportunities to reduce the size of the replacement.[41]

System needs where IRP is not screened out through this binary screening would next move to the two-stage IRP evaluation process, described in section 8.3, “Two-Stage Evaluation Process”.

Most parties accepted or agreed with the general intent to use screening criteria. CME and OEB staff noted that Enbridge Gas should use judgement in applying the criteria, if there are cases where it believes that further IRP consideration may be appropriate, even if the system need did not strictly pass the screening criteria.

<u>Specific screening criteria</u>

Enbridge Gas indicated that, after excluding system needs in the AMP that do not pertain to gas-carrying assets (buildings, fleet, IT, etc.), it would apply five binary screening criteria to identified system needs/constraints to determine whether further IRP evaluation is appropriate. Binary screening would exclude a system need from further IRP consideration.

These criteria were modified by Enbridge Gas throughout the proceeding. The final binary criteria proposed by Enbridge Gas, along with additional considerations, are described below.[42]

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40 Exhibit I.Staff.7
41 Exhibit JT 2.11
42 Exhibit J1.4

Emergent safety issues: *If an identified system constraint/need is determined to require a facility project in order for Enbridge Gas to ensure its continued ability to offer safe and reliable service or to meet an applicable law, it would not be a candidate for IRP analysis. An example of such a system constraint/need, and an emergent safety issue, would be if an existing pipeline sustained unanticipated damage and needed to be replaced as quickly as possible to ensure the safety of local communities and the Company's broader transmission and distribution systems. Enbridge Gas has acknowledged that longer-term safety related system constraints/needs may be appropriate for an IRPA solution and would be considered on a case-by-case basis.*

Enbridge Gas's proposed wording for this criterion evolved during the proceeding, in response to concerns from parties that many or most system needs could be classified as safety issues, and hence, screened out from further IRP consideration. Enbridge Gas's final proposed wording clarified that only system needs that were emergent safety issues would be excluded from IRP consideration using this criterion. Some parties submitted that, even with these revisions, the proposed wording was too broad or subjective.

Timing: *If an identified system constraint/need must be met in under 3 years, an IRPA cannot be implemented and its ability to resolve the identified system constraint/need cannot be verified in time. Therefore, an IRP analysis is not prudent. Exceptions to this criterion, could include: (i) Supply-side solutions like CNG; (ii) Bridging or market-based alternatives in combination with other IRPAs, where such exceptions/IRPAs can address a more imminent constraint/need.*

Enbridge Gas indicated that it expects most system needs to be identified more than three years in advance through its long-range planning process.[43] However, it noted that, at the outset of the IRP Framework, this will not be the case, as there will be a certain number of near-term needs that are known, but which have not yet been subject to the IRP Framework.

Customer-specific builds: *If an identified system constraint/need has been underpinned by a specific customer's (or group of customers') clear determination for a facility option and either the choice to pay a Contribution in Aid of Construction or to contract for long-term firm services delivered by such facilities (including new*

[43] Exhibit I.Staff.8d

subdivision or small main extensions) then it is not appropriate to conduct IRP analysis for those projects.

Some parties submitted that this criterion may not guarantee that a specific customer's preference for a facility project over an IRPA will not impose costs on other Enbridge Gas customers, and that if other customers do incur costs, Enbridge Gas should be required to consider IRPAs.

Environmental Defence specifically recommended that new subdivisions and small main extensions should not be excluded from further IRP consideration, as they are highly cost-effective opportunities for IRPAs.

CME and OEB staff submitted that Enbridge Gas should play a role in informing customers of potential IRPAs that might reduce their Contribution in Aid of Construction (by reducing the size and cost of the facility project).

Community expansion: *If a facility project has been driven by policy and related funding to explicitly deliver natural gas into communities to help bring heating costs down, then it is not appropriate to conduct an IRP analysis. Where Government grants are not identified for the specific purpose of growing natural gas access, then IRP could be considered for community expansion provided IRPAs such as district energy systems were included in scope.*

Enbridge Gas clarified that this was limited to specific projects named in O. Reg. 24/19 (Expansion of Natural Gas Distribution Systems).[44] O. Reg. 24/19 was made under the OEB Act (as amended by the *Access to Natural Gas Act*),[45] and supports the Government of Ontario's Natural Gas Expansion Program, which is intended to help expand access to natural gas to areas of Ontario that currently do not have access to the natural gas distribution system. O. Reg. 24/19 lists specific projects as being eligible for a maximum amount of rate reduction, which is collected from all gas customers, to fund a portion of the system expansion costs. On June 9, 2021, the Government of Ontario announced an additional 28 projects were selected for funding in the second phase of the Natural Gas Expansion Program, and O. Reg. 24/19 was amended to add these projects.[46]

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[44] Exhibit I.Staff.8f
[45] *Access to Natural Gas Act, 2018*, S.O. 2018, c. 15 - Bill 32
[46] Government of Ontario, "Ontario Expands Access to Natural Gas in Rural, Northern and Indigenous Communities", June 9, 2021.

Several parties submitted that the availability of project funding under O. Reg. 24/19 should not prevent Enbridge Gas from considering IRPAs. GEC and SEC encouraged consideration of lower-cost non-gas alternatives (which could potentially be delivered by parties other than Enbridge Gas) that would completely eliminate the need for a natural gas connection, while Anwaatin and LPMA noted the possibility of an IRPA that would reduce the size and cost of the facility project to connect these communities.

Pipeline replacement and relocation projects: *If a facility project is being advanced for replacement or relocation of a pipeline and the cost is less than $10 million, then that project is not a candidate for IRP analysis. Enbridge Gas acknowledges that for large pipeline replacement and relocation projects, there may be opportunities to reduce their size through consideration of IRPAs in the future. Accordingly, the Company would investigate such opportunities in the future on a case-by-case basis, taking into account the broader impacts of downsizing (e.g. creation of system bottlenecks or integrity and inspection concerns). The Company does not believe that IRP will be appropriate for smaller scale pipeline replacement projects (less than $10 million cost), as the cost savings that would result from downsizing pipeline size will not be significant enough to support consideration of IRPAs.*

Originally, Enbridge Gas proposed to screen out all replacement and relocation projects from further IRP analysis, but this proposal evolved over the course of the hearing. The $10 million threshold proposed by Enbridge Gas aligns with the proposed change to O. Reg. 328/03 under the *Ontario Energy Board Act, 1998*, that, if implemented, would raise the cost threshold as to which pipeline projects require Leave to Construct approval from $2 million to $10 million.[47]

Some parties expressed concerns that a $10 million threshold may be too high and would screen out a large number of system needs from further IRP evaluation.

GEC submitted that this criterion should not be used to screen out replacement and relocation projects where pipeline size or capacity is being increased. Enbridge Gas agreed with this proposal.

[47] Environmental Registry proposal 019-3041. On July 16, 2021, a second proposal (Environmental Registry proposal 019-4029) was posted, seeking comments on the specific proposed regulatory amendments.

Findings

The OEB concludes that the establishment of screening criteria to select which system needs require IRP assessment is appropriate.

The OEB agrees that there must be a focus on those situations where there is a reasonable expectation that an IRPA could efficiently and economically meet the system need. The OEB notes that other jurisdictions have used initial screening for IRP suitability including criteria such as minimum lead time required and minimum project costs.

The OEB has determined that the following criteria will be appropriate for the first-generation IRP Framework. With more experience, there may be an opportunity to modify these criteria in the future.

<u>Emergent Safety Issues</u>

The first criterion deals with urgent or imminent issues. The OEB agrees with Enbridge Gas that the safety and reliability of the gas system is paramount. Removing constraints that jeopardize this system performance does not allow time for the development and assessment of an IRP Plan.

i. **Emergent Safety Issues** – *If an identified system constraint/need is determined to require a facility project for Enbridge Gas to offer safe and reliable service or to meet an applicable law, an IRP evaluation is not required. An example of such a system constraint/need, and an emergent safety issue, would be if an existing pipeline sustained unanticipated damage and needed to be replaced as quickly as possible to ensure the safety of local communities and Enbridge Gas's broader transmission and distribution systems. Longer-term safety related system constraints/needs may be appropriate for an IRP Plan and should be considered on a case-by-case basis.*

<u>Timing</u>

It takes time to assess and implement an IRP Plan along with demonstration that the constraint is being mitigated. Once a ten-year AMP consistent with the IRP Framework has been in place for several years, there should be fewer situations where a timing criterion is needed; however, for this first-generation IRP Framework, the OEB is establishing a timing criterion. The OEB notes that the use of supply-side options might be possible to meet an identified need within a shorter period.

ii. ***Timing*** *– If an identified system constraint/need must be met in under three years, an IRP Plan could not likely be implemented and its ability to resolve the identified system constraint could not be verified in time. Therefore, an IRP evaluation is not required. Exceptions to this criterion could include consideration of supply-side IRPAs and bridging or market-based alternatives where such IRPAs can address a more imminent need.*

Customer-Specific Builds

Where the customer fully pays for the incremental infrastructure costs associated with a facility project, in the form of a Contribution in Aid of Construction, the OEB finds that consideration of an IRP Plan will not be required.[48] However, the OEB encourages Enbridge Gas to discuss DSM opportunities with customers to potentially reduce the size of the build.

iii. ***Customer-Specific Builds*** *– If an identified system need has been underpinned by a specific customer's (or group of customers') clear request for a facility project and either the choice to pay a Contribution in Aid of Construction or to contract for long-term firm services delivered by such facilities, then an IRP evaluation is not required.*

Community Expansion & Economic Development

Given the goal of the Ontario Government's Access to Natural Gas legislation[49] to extend gas service to designated communities, the OEB will not require Enbridge Gas to develop an IRP Plan or consider alternatives to the infrastructure facilities to meet this need. However, the OEB encourages Enbridge Gas to discuss DSM opportunities with customers to potentially reduce the size of the build.

iv. ***Community Expansion & Economic Development*** *– If a facility project has been driven by government legislation or policy with related funding explicitly aimed at delivering natural gas into communities, then an IRP evaluation is not required.*

[48] The incremental costs recovered through a Contribution in Aid of Construction are set at an amount that reduces the capital cost of a project for Enbridge Gas ratepayers such that the project becomes economically feasible, which generally requires a profitability index greater than or equal to one.
[49] *Access to Natural Gas Act, 2018*, S.O. 2018, c. 15 - Bill 32

<u>Pipeline Replacement and Relocation Projects</u>

The OEB has determined that a minimum cost of the facility project is required to justify the time and effort to conduct an IRP evaluation and potentially develop an IRP Plan. The OEB finds that projects under $2 million should be screened out unless the government makes regulatory changes establishing a $10 million threshold for OEB Leave to Construct approvals, in which case, the criteria should use $10 million to determine if an IRP evaluation is appropriate.

v. ***Pipeline Replacement and Relocation Projects** – If a facility project is being advanced for replacement or relocation of a pipeline and the cost is less than the minimum project cost that would necessitate a Leave to Construct approval, then an IRP evaluation is not required.*

8.3 IRP Assessment Process Step 3: Two-Stage Evaluation Process

For system needs progressing past the initial IRP binary screening, Enbridge Gas proposed determining whether to proceed with an IRP Plan through a two-stage evaluation.[50] First, Enbridge Gas would determine whether potential IRPAs could meet the identified constraint/need. If yes, then Enbridge Gas would compare one or more IRP Plans to the baseline Facility Alternative, using a Discounted Cash Flow-plus (DCF+) economic test, to determine the optimum solution to meet the system need.

Enbridge Gas indicated that the two-stage evaluation process would commence sufficiently far in advance of the date that the constraint/need must be met in order to allow for time for an IRP Plan to be developed, approved, implemented and monitored for effectiveness in advance of the date when a facility project would be required.

<u>Stage 1: Technical Evaluation</u>

The first stage would look at the technical viability of potential IRPAs to reduce peak demand to the degree required to meet the identified system need, using best available information to determine whether an IRP Plan including one or more IRPAs would be a viable option. Enbridge Gas noted that to address the lack of experience with IRPAs and the associated risk of under delivery of peak period savings, it may need to employ a derating factor (i.e., assuming less than 100% of the forecast peak demand reduction

[50] Argument-in-Chief, pp. 27-31

from the IRPAs would be delivered). This would lead to Enbridge Gas oversubscribing the amount of IRPAs, in order to have adequate assurance of expected results.

Parties had few comments on the first stage of the evaluation process and were generally supportive. Enbridge Gas confirmed that it will consider all feasible and available IRPAs when conducting the stage one technical evaluation, and indicated that its information on best available information on IRPAs included with its annual IRP report would aid with this consideration.

Several parties commented on Enbridge Gas's intent to use derating factors and questioned the need for oversubscription to IRPAs, or submitted that treating this aspect of risk related to IRPAs but not addressing other economic risks associated with facility projects was one-sided. GEC submitted that as experience is gained with IRPAs, the derating factor should be adjusted to more accurately reflect the risk. OEB staff submitted that the reliability and economic risks associated with both IRPAs and Facility Alternatives should be quantified within the subsequent economic evaluation, to the degree possible.

Stage 2: Economic Evaluation

Enbridge Gas proposed that the economic evaluation would consist of a three-phase DCF+ evaluation to compare the IRP Plan(s) to the baseline Facility Alternative. This test would be based on the three-phase economic test that Enbridge Gas is required to use to assess the costs and benefits of potential transmission system expansions, under the parameters established by the *Report of the Board on the Expansion of the Natural Gas System in Ontario* (the E.B.O. 134 report). The principles of this test are summarized in the OEB's *Filing Guidelines on the Economic Tests for Transmission Pipeline Applications*.[51]

In the context of IRP, Enbridge Gas calls this a DCF+ test.

- Phase 1 assesses the economic benefits and costs from the utility perspective, and indicates whether the project is likely to result in future increases to utility rates.

[51] A recent example of how this three-phase test (including the concept of summing the results of the three phases) has been used for transmission system expansions can be seen for the proposed Dawn-Parkway expansion project (EB-2019-0159): Application and Evidence, Exhibit A, Tab 8. Enbridge Gas has also provided a hypothetical example of how this test could work in comparing facility projects and IRPAs in Exhibit JT 2.15.

- Phase 2 assesses the incremental economic benefits and costs incurred by customers from the IRP Plan(s) or Facility Alternative(s).
- Phase 3 assesses the incremental societal benefits and costs.

The categories of benefits and costs that Enbridge Gas proposes to include in each phase are shown in Table 2.[52]

Table 2: Discounted Cash Flow-Plus Test Costs and Benefits

Benefit/Cost	Phase 1	Phase 2	Phase 3
Benefits			
Incremental Revenues	x		
Avoided Utility Infrastructure Costs [2]	x		
Avoided Customer Infrastructure Costs [3]		x	
Avoided Utility Commodity/Fuel Costs [4]	x		
Avoided Customer Commodity/Fuel Costs [5]		x	
Avoided Operations & Maintenance	x		
Avoided Greenhouse Gas Emissions		x	
Other External Non-Energy Benefits			x
Costs			
Incremental Capital Expenditure [1]	x		
Incremental Operations & Maintenance [1]	x		
Incremental Taxes	x		
Incremental Utility Commodity/Fuel Costs [4]	x		
Incremental Customer Commodity/Fuel Costs [5]		x	
Incremental Greenhouse Gas Emissions		x	
Incremental Customer Costs		x	
Other External Non-Energy Costs			x

Notes:
(1) Capital and Operations & Maintenance is inclusive of program administrative costs
(2) Avoided or reduced infrastructure capital costs of the utility (e.g., 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)

52 Exhibit JT 2.2

A net present value would be calculated for each phase. Results from each phase would be presented separately for transparency, but would also be summed together.

The DCF+ results for the IRP Plan(s) and the baseline Facility Alternative would be compared to one another, to determine which alternative is optimal. IRP Plans that included some combination of IRPA and facility project could also be tested using this approach.

While economics would be a factor in the final decision as to how best meet a system need, Enbridge Gas indicated that other considerations (safety, public policy, reliability) that are potentially difficult to quantify would also play a role in the final decision as to which IRPA or facility project is selected.

The primary alternative economic approach discussed in this hearing was a Total-Resource Cost-plus (TRC+) test. This is a single-phase test that is used in Ontario to assess the cost-effectiveness of DSM programs, by measuring the energy-related benefits and costs of DSM programs experienced by both the gas utility system and participants in DSM programs, as well as an adder that accounts for non-energy benefits associated with DSM programs.[53] Similar to the TRC+ test is the Societal Cost Test, which Con Edison has proposed to use as its cost-effectiveness test to evaluate IRP activities in New York State.[54] The Societal Cost Test is also a single-phase test that assesses all energy and non-energy related costs and benefits from a societal perspective.

Parties were split between the merits of a DCF+ test or TRC+ test.

Enbridge Gas expressed a preference for the three-phase DCF+ test, as opposed to an "all-in-one" test such as the TRC+ test, because the TRC+ test on its own does not provide any indication of the rate impact or potential for cross-subsidization of the IRP Plans and Facility Alternatives considered (information that is provided in phase 1 of the proposed DCF+ test). Enbridge Gas also noted that while the TRC+ test is used in Ontario to measure the cost-effectiveness of energy efficiency type programs, it has little or no experience using a TRC+ test to evaluate facility projects in the context of

[53] Ontario Energy Board, Demand Side Management Framework for Natural Gas Distributors (2015-2020), s.9
[54] Con Edison, Proposal For Use of a Framework to Pursue Non-Pipeline Alternatives to Defer or Eliminate Capital Investment in Certain Traditional Natural Gas Distribution infrastructure, September 15, 2020, p. 24

meeting system needs, in contrast to Enbridge Gas's extensive experience using the DCF test.

Enbridge Gas's proposal indicated that the results of all three phases of the DCF+ test would be summed together, with the overall results used to determine which alternative is optimal.

The submissions of many of the other parties supporting the DCF+ test indicated that the first phase of the DCF+ test (which assesses the economic benefits and costs from the utility perspective, and identifies whether the project is likely to result in future increases to utility rates) should be given primacy in the economic evaluation. These parties submitted that the test selected needs to focus on solutions that meet the system constraint and that benefit all Enbridge Gas customers paying postage stamp transmission and distribution rates. They expressed the concern that the TRC+ test could require Enbridge Gas customers to pay more for an IRP Plan than they would otherwise have to pay for a pipeline solution that meets the same need. This is because an IRP Plan could score favourably on the TRC+ test, even if the benefits go primarily to customers participating in an IRPA (e.g., a geotargeted energy efficiency program) or to society as a whole, not to all Enbridge Gas customers. APPRO noted (in supporting a DCF+ approach) that phase 1 of the DCF+ test served a gating function, protecting Enbridge Gas customers from this outcome. Similarly, IGUA submitted that to the extent that an IRPA drives a higher cost than the baseline utility infrastructure which it is intended to avoid, it should not be approved, even if its overall societal benefit is calculated to be superior to that of the baseline utility solution.

Several parties argued that the TRC+ test is more appropriate, based on three main points. First, no other jurisdiction uses a test similar to the DCF+ test to compare facility and non-facility options (including demand-side options). Second, the TRC+ test is the best way to evaluate the overall cost-effectiveness of alternatives taking into account all relevant factors, including potential commodity cost savings to customers and greenhouse gas emissions reductions (which can be considered in phases 2 or 3 of the DCF+ test, but not in the first phase). Third, it is not logical to assess demand-side IRPAs using a different economic test than the OEB currently uses to evaluate Enbridge Gas's DSM activities under the DSM Framework.

Several parties also raised methodological concerns with Enbridge Gas's proposal to add the results of the three phases of the DCF+ test together.

Some parties supporting a TRC+ test indicated that it could be appropriate to include a secondary test (similar to the DCF+ phase 1) to assess ratepayer impact considerations of IRP Plans and Facility Alternatives.

Further Work on Economic Evaluation Methodology

All parties, whether supporting a DCF+ or TRC+ economic test, agreed that further work should be done regarding the specifics of using the preferred test for comparing IRPAs and Facility Alternatives. Guidehouse indicated in testimony that the existing tests leave a lot of gaps and uncertainties about how they would be applied to IRP. Enbridge Gas accepted Guidehouse's recommendation that parties work to complete a Benefit Cost Analysis Handbook or supplemental guide to E.B.O 134 to improve the comprehensiveness of the DCF+ test for economic evaluations, and that this would be an appropriate activity for the IRP Technical Working Group.

Some parties raised specific considerations regarding the treatment of costs and benefits. Several parties proposed that Enbridge Gas value avoided greenhouse gas emissions based on the assumption that this value will continue to rise over time, instead of assuming that the price will remain at $50/tonne CO_2e after 2022, as is currently in law. This could include (but would not necessarily be limited to) the federal government's intent to implement a price on greenhouse gas emissions that will continue to rise to $170/tonne CO_2e by 2030. Enbridge Gas indicated that it could accommodate adding a scenario to its DCF+ analysis that would include different carbon pricing assumptions, although it may not necessarily agree with other parties as to how the results of such an alternative scenario would be used in determining the preferred solution.

OEB staff and several other parties made additional suggestions for specific items that should be included in the economic test. OEB staff submitted that the economic test should include impacts on Enbridge Gas's gas supply costs and should also quantify reliability and economic risk if possible. Enbridge Gas submitted that it would take these suggestions into consideration, but including these types of details in the IRP Framework is a level of granularity that is not necessary or possible at this time.

Cross-Subsidization Concerns For Projects Benefiting New Customers

Several parties, whether favouring a TRC+ test or DCF+ test to compare IRPAs and Facility Alternatives, indicated that the existing E.B.O. 188 and E.B.O. 134 tests should continue to be required as economic tests to assess whether to proceed with system expansion projects to serve new customers. As noted above, the E.B.O. 134 test is a three-phase test used as an economic test for transmission system expansions, that Enbridge Gas has modeled its DCF+ test on. The E.B.O. 188 test[55] is used as an economic test for a proposed distribution system expansion and only includes the first phase of the DCF test.

OEB staff noted that Enbridge Gas's economic feasibility policies[56] supporting the E.B.O. 188 guidelines enable Enbridge Gas to require a customer contribution, in the form of a Contribution in Aid of Construction, System Expansion Surcharge, or Temporary Connection Surcharge, to address cross-subsidization concerns between new and existing customers. These customer contributions can improve the net present value and profitability index of a project under the E.B.O. 188 test (DCF phase 1). OEB staff submitted that this approach could also be used for IRPAs. OEB staff submitted that Enbridge Gas should review its economic feasibility policies to ensure that the system reinforcement costs used as inputs are based on a forward-looking approach that accounts for system needs/constraints identified in the AMP, and submit the revised policies in its rebasing application. Enbridge Gas indicated that it would consider including this update into its economic feasibility policies to be presented for approval at rebasing, but did not believe that this needed to be ordered by the OEB or included in the IRP Framework.

Findings

Technical Evaluation

The OEB concludes that it is appropriate for Enbridge Gas to undertake a technical evaluation to first determine if the IRPAs considered can meet the need, prior to doing an economic evaluation. The OEB accepts that Enbridge Gas may use derating factors or oversubscription of IRPAs to address uncertainty regarding forecast savings. These derating factors may be relevant to both the technical and economic evaluations. The OEB has also determined that Enbridge Gas should include in its request for OEB approval of specific IRP Plans both the level of oversubscription and the supporting rationale.

[55] The E.B.O. 188 test is described in the OEB's Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario
[56] The most recent version of these policies can be found in EB-2020-0094, Exhibit C, Tab 2, Schedules 1 and 2 for the EGD and Union rate zones.

Economic Evaluation

The OEB concludes that the DCF+ test, including its focus on rate impacts (as identified in phase 1 of the DCF+ test), should be the economic evaluation test used in the IRP Framework. The OEB agrees that the test selected should be the one that best aligns with the goal and purpose of IRP planning, which is to address the system needs of Enbridge Gas's regulated operations and identify and implement the solution that is in the best interest of Enbridge Gas and its customers. The purposes of DSM and IRP are distinct from each other. The OEB has determined that the primary objective of Enbridge Gas's post-2021 DSM Plan should be to assist customers in making their homes and businesses more efficient in order to better manage their energy bills.[57] DSM is aimed at reducing annual natural gas usage, and IRP is aimed at reducing peak demand in specific geographic areas to replace infrastructure investment with an IRPA investment. Given the separate purpose, it is reasonable that a different economic test should be applied in the IRP Framework than in the DSM Framework. The OEB finds that an IRP Plan is attempting to reduce the longer-term cost to all Enbridge Gas customers, accordingly it is important to have an evaluation test that looks at impacts from the gas customer perspective. That is also consistent with the OEB's statutory objectives.

Where the two-stage evaluation process reveals that an IRP Plan is the best alternative to meet an identified need/constraint, then Enbridge Gas is encouraged to make application to the OEB for approval of the IRP Plan, and then implement and monitor the IRP Plan and make adjustments as appropriate. The OEB finds that Enbridge Gas should be given some discretion in selecting an alternative to meet a system need that does not have the highest score on phase 1 of the DCF+ test, as there may be considerations or factors that are important in phases 2 or 3, or are difficult to quantify. However, Enbridge Gas would require full justification of their proposal if they recommend a higher cost alternative.

Further Work on Economic Evaluation Methodology

The OEB accepts the categories of benefits and costs proposed by Enbridge Gas for the three phases of the DCF+ test (shown in Table 2) for the use of this test in the IRP Framework. The OEB recognizes that the DCF+ test could be improved to better identify and define the costs and benefits of Facility Alternatives and IRPAs, and clarify how these costs and benefits should be considered within the DCF+ test. This could

[57] OEB Letter, Re: Post-2020 Natural Gas Demand Side Management Framework, December 1, 2020

include expanding the inputs to recognize increasing carbon costs, the risk that a constraint remains unresolved, and impact on gas supply costs. The OEB directs Enbridge Gas to study improvements to the DCF+ test for IRP. Enbridge Gas is encouraged to consult with the IRP Technical Working Group and to use the IRP pilot projects as a testing ground for an enhanced DCF+ test. In particular, the OEB considers it appropriate for the Technical Working Group to consider how different carbon pricing scenarios should be used in the DCF+ calculation. The OEB directs that Enbridge Gas file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan.

Cross-Subsidization Concerns for Projects Benefiting New Customers

The E.B.O. 134 and 188 tests were designed to determine whether a natural gas distribution or transmission expansion project was compatible with the OEB's objective to facilitate rational expansion of transmission and distribution systems. The OEB concludes that the results of the DCF+ test that will be required in the IRP Framework will be of similar assistance in determining whether a proposed IRP Plan to serve new customers is compatible with this objective.

This emphasis on cost-effectiveness and avoiding cross subsidization between new customers and existing customers led to the consideration of customer contributions, in the form of a Contribution in Aid of Construction, System Expansion Surcharge, or Temporary Connection Surcharge for infrastructure projects. The OEB concludes that these same charges could be applied to an IRP Plan where the IRP Plan is being proposed for the benefit of new customers, to reduce cross-subsidization and improve the net present value and profitability index of an IRP Plan in part 1 of the DCF+ test.

8.4 IRP Assessment Process Step 4: Periodic Review

Enbridge Gas indicated that where circumstances change (for example, the nature or timing of an identified need/constraint alters materially, or significant policy changes are announced by government or the OEB), it would review its IRP determinations and report on the outcome of its re-evaluation within the AMP and/or annual reporting. Under changes with system-wide implications and importance, Enbridge Gas suggested that a discussion with the IRP Technical Working Group might occur to review the change.

Several parties submitted that Enbridge Gas should inform the OEB and stakeholders at the time such changes were identified, with the potential for further review. Enbridge Gas opposed this suggestion, and indicated that, in its initial IRP evaluation process, it would be reporting on and engaging with stakeholders on a periodic basis at a higher level, not on a project-by-project basis, and that the same approach was appropriate when circumstances change and decisions are revisited.

Enbridge Gas also clarified that, in regard to modifications to approved IRP Plans, it proposed to seek approval from the OEB for outright cessation of an approved IRP Plan, but would not seek OEB approval to spend less than previously approved amounts.

Findings

The OEB recognizes that material changes may occur that could impact Enbridge Gas's determination as to how best to meet a system need. These may include changes occurring when implementing an IRP Plan after receiving project approval. The OEB believes that updates of this nature are encompassed in the information that the OEB is requiring Enbridge Gas to include as part of its annual IRP report (see chapter 14, "Monitoring and Reporting"). If Enbridge Gas plans to increase its spending on an approved IRP Plan by more than 25%, it will need to request OEB approval for the change, as discussed in chapter 13 ("Future IRP Plan Applications").

9 ALLOCATION OF IRP RISKS

There are risks associated with the development of an IRP Plan and the selection of projects to address constraints. The OEB has identified three significant categories of risk that need to be addressed in developing the IRP Framework.

First, has the IRP Assessment Process accurately assessed the system constraint and evaluated alternative IRPAs or infrastructure builds (Plan Accuracy)? Second, if an IRPA is recommended and approved, will it deliver the reduction to load required to eliminate the constraint (Success of IRP Plan Implementation)? Finally, will the potential stranding of assets currently considered for pipeline infrastructure also apply to IRPAs if the load does not materialize (Potential Stranding of Assets)?

Plan Accuracy

The lack of a comprehensive assessment of alternatives to infrastructure builds has been a risk identified several times in recent OEB Leave to Construct decisions. Several parties raised a concern that by the time Enbridge Gas brings forward an application for a facility project or IRP Plan there may be limited options for the OEB if it concludes Enbridge Gas has not chosen the best option to meet a system need. There is a risk that it would no longer be possible to implement alternative options without compromising safety or reliability. Enbridge Gas indicated that this risk will be low if Enbridge Gas follows its proposed planning framework, including its IRP Assessment Process, annual status updates to its AMP, and consideration of stakeholder feedback.

Enbridge Gas acknowledged that it bears the risk that the OEB might not approve an as-filed Leave to Construct application if the OEB determines that an IRP Plan would have been a better approach. Several parties submitted that, in this circumstance, the OEB may approve something less than full cost recovery.

Success of IRP Plan Implementation

Enbridge Gas submitted that it should not bear the risk that an approved IRP Plan may not succeed in creating the forecast peak demand reduction, as IRP is a new activity, and it is being pursued for the benefit of Enbridge Gas's ratepayers.[58]

Enbridge Gas submitted that if an IRP Plan does not meet expectations, and therefore it needs to be expanded, or where facilities need to be built notwithstanding the IRP Plan,

[58] Argument-in-Chief, p. 18

then the costs of the additional activities should also be paid by ratepayers. Enbridge Gas argued that, due to the greater uncertainty associated with IRP, if it is at risk for lower-than-expected results from IRP Plans, then it will essentially be penalized for pursuing IRP.

Environmental Defence supported the general principle that Enbridge Gas should not end up bearing more risk for IRP Plans than it does for traditional infrastructure projects.

Several parties disagreed with the treatment of risk allocation for IRP Plans as framed by Enbridge Gas, with these parties indicating that Enbridge Gas should bear some risk for the performance of IRP Plans, as it does for facility projects. Some parties tied this to Enbridge Gas's request to earn a rate of return on IRP Plan costs (chapter 12, "IRPA Cost Recovery and Accounting Principles"), indicating that earning a rate of return should require Enbridge Gas to assume a degree of risk. In reply, Enbridge Gas argued that taking the risk of whether an IRP Plan will deliver all the forecast peak demand reductions is not the same as taking the risk that a facility will operate as designed. Enbridge Gas submitted that IRP is a new activity and the peak demand reductions that may be achieved through IRP Plans are much less certain than what will be achieved through facility investments.

Other parties indicated that the risk Enbridge Gas bears for IRP Plan implementation can be addressed through the OEB's prudence review of actual incurred IRP Plan costs. OEB staff submitted that the OEB's prudence review could also take into consideration whether Enbridge Gas had taken appropriate action to adjust its investments in approved IRP Plans as needed, based on its implementation, evaluation and monitoring of "in-flight" IRP Plans. OEB staff suggested that the IRP Framework could acknowledge that there may be a greater degree of performance and cost risk associated with IRP as a new activity, in comparison with facility projects, and that the OEB would take this into account in its prudence review.

Potential Stranding of Assets

SEC raised the potential for stranded assets with IRPAs approved through an IRP Plan. In developing facility projects or IRP Plans, SEC submitted that Enbridge Gas should ensure that they address the risk that assets will be stranded, including active steps to mitigate that risk, and scenario analysis to ensure that the plans will remain robust in the face of that risk.

Findings

Plan Accuracy

The OEB acknowledges the concern that previous Leave to Construct applications have not adequately considered alternatives to the infrastructure build. This IRP Framework and the planned pilots are expected to reduce the risk of inadequate consideration of alternatives. The IRP Assessment Process (including needs identification, binary screening, and evaluation of alternatives), stakeholdering, and experience gained through pilots should result in more prudent and effective integrated resource system planning.

The OEB finds that Enbridge Gas is making considerable effort to improve its planning process, and this is expected to reduce the risk of not developing alternatives that are superior to facility projects where appropriate.

As noted in chapter 8 ("IRP Assessment Process"), the OEB is not requiring Enbridge Gas to seek approval for the results of its IRP Assessment Process prior to project-specific applications for approval of an IRP Plan or a Leave to Construct. Enbridge Gas has considerable experience with Leave to Construct applications, including circumstances in which conditions of approval or modifications made to the original request have been required by the OEB. Furthermore, the OEB retains the authority to deny recovery of costs if it determines that Enbridge Gas was not prudent in considering alternatives, and Enbridge Gas acknowledged this possibility.

Success of IRP Plan Implementation

The OEB finds that prudently incurred costs associated with an approved IRP Plan will be eligible for cost recovery.

The OEB acknowledges that there may be a greater degree of performance and cost risk associated with IRPAs and IRP Plans in comparison with facility projects. Enbridge Gas has extensive experience with the successful implementation of facility projects, and the nature of these types of projects means that the outcome is largely in Enbridge Gas's control. There is less experience in addressing system constraints using IRPAs like geotargeted DSM or demand response, and these IRPAs depend on consumer behaviour for success. The OEB expects to take this into consideration in its prudence review. However, where Enbridge Gas does not act prudently and in accordance with an approved IRP Plan, then it may be at risk for recovery of some portion of IRP investments that are deemed imprudent.

As Enbridge Gas gains experience with IRP Plans and IRPAs, the risk of non-performance is expected to diminish. When seeking cost recovery, the explanation of what was done to mitigate the risk, and what portion of the risk should be allocated to customers (e.g., by allowing recovery of cost overruns), will require careful review by the OEB.

Potential Stranding of Assets

The risk of stranded assets is a concern for both infrastructure builds and for IRPAs. The OEB has limited experience with the treatment of stranded assets. The examination of the treatment of stranding of assets in other jurisdictions and the findings of the Technical Working Group on this topic might help provide a better understanding of stranded assets and options to allocate the costs between Enbridge Gas and its customers. At this time, the OEB will continue to emphasize the demonstration of prudence by Enbridge Gas, at both the system planning and project planning levels, when addressing the allocation of stranded costs.

10 STAKEHOLDER OUTREACH AND ENGAGEMENT PROCESS

Enbridge Gas requested approval of a proposed three-component stakeholdering process, including a purpose-specific stakeholder Technical Working Group to support IRPA development and to identify and discuss new IRP solutions and IRP avoided costs and benefits.[59]

Enbridge Gas's proposed three-component process includes:

1. Gathering of Stakeholder Engagement Data and Insight: Seeking insights from stakeholders and various market participants by working within existing stakeholder engagement channels, on an ongoing basis, to mitigate incremental expenses and leverage existing relationships.
2. Stakeholder Days: Annual regional stakeholder events focused on IRP to discuss plans and progress with IRP, including specific discussion of needs/constraints identified in the AMP and the plans to address such items through IRP. These would be held on an annual basis shortly after Enbridge Gas files its AMP update within Phase 2 of the annual rates proceeding.
3. Targeted Engagement: Project-specific consultation dealing with specific IRPAs or IRP Plans (identified for a specific need in a specific geographic region), with stakeholders from the specific geographic area relevant to the IRPA. Enbridge Gas also noted that it intends to consult with any potentially impacted Indigenous group in relation to proposed IRP Plans, IRPAs and Leave to Construct applications. Project-specific consultation would be done in advance of seeking project approval from the OEB.

Enbridge Gas's stakeholdering proposal includes a commitment to record comments from stakeholders and Indigenous groups participating in components 2 and 3 and the responses from Enbridge Gas to these comments, which would be filed in any subsequent IRP Plan/Leave to Construct application.

In addition, Enbridge Gas supported the creation of a purpose-specific Technical Working Group comprised of interested parties to have discussions regarding IRP issues of more general interest. Topics that might be addressed include potential IRPAs, determination of the best approach to consider avoided costs and benefits for IRPAs and Facility Alternatives, and the development of natural gas IRP in other

[59] Argument-in-Chief, p. 14

jurisdictions. A first area of focus for the Technical Working Group would be to provide input on the consideration and implementation of IRP pilot projects. Enbridge Gas proposed that it would lead the Technical Working Group.

Enbridge Gas indicated that it does not support any approach to stakeholdering that would give stakeholders a “vote” in system planning decisions.

Three Component Stakeholder Approach

Views were mixed on Enbridge Gas’s proposed stakeholdering approach. Many parties supported Enbridge Gas’s proposed approach. Those parties that believed Enbridge Gas’s stakeholdering approach to be insufficient generally indicated a preference for greater stakeholder involvement (e.g. the ability to ask interrogatories, OEB adjudication in the event of disputes) in Enbridge Gas’s determinations regarding specific planning decisions, such as screening out IRPAs for system needs, prior to seeking approval from the OEB for specific projects. In reply, Enbridge Gas indicated that it does not agree with stakeholder proposals for more regulatory process and ongoing OEB oversight throughout the stakeholdering process. The OEB’s findings regarding the OEB role in planning decisions made by Enbridge Gas prior to applications are discussed in chapter 8 (“IRP Assessment Process”).

Anwaatin raised issues specific to engagement and consultation with Indigenous peoples, including Duty to Consult requirements. These issues are discussed separately in chapter 11 (“Indigenous Engagement and Consultation”).

Several parties provided suggestions designed to ensure that all interested stakeholders, including low-income customer representatives, were aware of Enbridge Gas’s stakeholdering activities and were able to participate. In reply, Enbridge Gas agreed to creating a list of interested parties and ensuring that all such parties receive notice of stakeholdering activities. Enbridge Gas suggested that an IRP dedicated web page would be the most efficient way to inform stakeholders.

OEB staff supported Enbridge Gas’s proposal to keep a written record of consultation activities to inform future project-specific decisions. Pollution Probe suggested that the IRP webpage could also include similar information (aligning with IESO practices), such as presentations and meeting minutes. Enbridge Gas indicated that it was open to this proposal.

Technical Working Group

Most parties supported the establishment of an IRP Technical Working Group, but indicated a preference for the OEB to lead the group, similar to the approach used with the OEB's Demand-Side Management Evaluation Advisory Committee. In its reply argument, Enbridge Gas disagreed, indicating that the purpose of the proposed IRP Technical Working Group was to provide Enbridge Gas with guidance and perspective from expert advisors to determine the appropriate direction and approach for IRP process and decisions.

OEB staff and SEC made recommendations for the focus of the Technical Working Group that were similar to Enbridge Gas's proposal. OEB staff listed the following topics on which the Technical Working Group could potentially provide input to the OEB and Enbridge Gas:

- Consideration and implementation of IRP pilot projects
- Cost-benefit considerations regarding IRPAs
- Learnings on specific types of IRPAs, and IRP implementation in other jurisdictions
- Accounting treatment of IRPA costs

GEC submitted that the Technical Working Group should be mandated to make recommendations to the OEB for changes to the IRP Framework where the Technical Working Group determines such changes are needed.

Some parties proposed a different role for the Technical Working Group (or additional groups) with more focus on contributing to or reviewing the specific system planning determinations of Enbridge Gas. For example, EFG's expert evidence recommended a model similar to the Vermont System Planning Committee, which has a greater emphasis on reviewing specific system needs and determining the optimal solution, including voting rights to document positions on issues. GEC proposed that the Technical Working Group would review all IRP screening decisions and report annually to the OEB. Enbridge Gas objected to these proposals, indicating that they inappropriately seek to transfer oversight and direction for IRP system planning decisions from Enbridge Gas to stakeholders.

Some parties made recommendations for membership on the Technical Working Group (in addition to membership of Enbridge Gas and OEB staff), with suggestions including representatives of Indigenous customers, environmental groups, consumers, low-income customers, the IESO or electricity distributors/transmitters, and IRPA service providers.

Findings

The OEB has determined that the three components of Enbridge Gas's proposed Stakeholder Engagement Process will provide valuable input into Enbridge Gas's IRP activities and shall be incorporated in the IRP Framework. The OEB also directs the establishment of a website by Enbridge Gas to facilitate the broad sharing of information on IRP stakeholdering efforts.

In addition to the three component stakeholder process, the OEB will also establish an IRP Technical Working Group led by OEB staff. This will be similar to the widely endorsed and successful Demand-Side Management Evaluation Advisory Committee. Leadership by OEB staff will promote objectivity and impartiality. The IRP Technical Working Group will have an objective of providing input on IRP issues that is of value to both Enbridge Gas in implementing IRP, and to the OEB in its oversight of the IRP Framework. The IRP Technical Working Group is being established for the first-generation IRP Framework; continuation of a Technical Working Group for next generations will be reassessed based on the needs at that time. It is expected that IRP will become a routine matter of planning within Enbridge Gas over time.

OEB staff will establish a terms of reference and select the membership. The OEB expects that the first priorities will be consideration and implementation of the IRP pilot projects, and enhancements or additional guidance in applying the DCF+ evaluation methodology. The OEB agrees with the suggestion that IRP progress in other jurisdictions should continue to be monitored. This may be a consideration for the Technical Working Group once the initial priorities have been addressed.

The IRP Technical Working Group will also be expected to review a draft of Enbridge Gas's annual IRP report, with the review coordinated by OEB staff. Enbridge Gas should provide a draft of the annual IRP report to the IRP Technical Working Group far enough in advance of its planned filling to the OEB to allow the Technical Working Group time to review and comment. A report from the Technical Working Group to the OEB should be filed by OEB staff in the same proceeding in which Enbridge Gas's annual IRP report is filed. The Technical Working Group report should include any comments on Enbridge Gas's annual IRP report, including material concerns that remain unresolved within the Technical Working Group, and may also describe other activities undertaken by the Technical Working Group in the previous year.

One topic that should be addressed by the IRP Technical Working Group in the future is the recommendation of IRP metrics for the OEB's consideration, as noted in chapter 14 ("Monitoring and Reporting"). Other topics could include the treatment of stranded assets in other jurisdictions, as noted in chapter 9 ("Allocation of IRP Risks").

As Enbridge Gas noted, under the Ontario regulatory model, Enbridge Gas is the natural gas system operator with the sole responsibility to make final system planning decisions and to advance IRP Plans and/or Leave to Construct applications. Enbridge Gas does not support the Technical Working Group having "voting rights" and the OEB agrees with this position. While Enbridge Gas is expected to consider any input provided by the Technical Working Group, the Technical Working Group will not have "voting rights" that bind Enbridge Gas with regards to its system planning decisions.

Enbridge Gas submitted that parties included in the IRP Technical Working Group should have relevant demonstrable technical expertise that relates to and informs the activities to be addressed by the IRP Technical Working Group. The OEB agrees with this recommendation. The OEB directs that membership should include Enbridge Gas, OEB staff, independent experts, and experienced non-utility stakeholders. Membership may also include the Independent Electricity System Operator, if appropriate. Beyond this, the OEB is not establishing requirements for representation of specific interests on the Technical Working Group, as recommended by some parties. Selection should be based on the value that potential members can bring to implementing and improving the IRP Framework and Enbridge Gas's IRP activities under the Framework. The IRP Technical Working Group will need to be kept to a manageable size to ensure timely and effective consultation. The OEB expects there should be no more than 10 people.

The OEB has concluded that establishing the Technical Working Group is a priority and must be established shortly after this IRP Framework is issued. OEB staff will establish the IRP Technical Working Group, including a terms of reference, and the initial selection of Working Group members, by the end of 2021.

11 INDIGENOUS ENGAGEMENT AND CONSULTATION

Anwaatin submitted that, in the development of its IRP proposal, Enbridge Gas failed to carry out Indigenous consultation and engagement. Anwaatin requested that the OEB find that Enbridge Gas failed to comply with the Indigenous People's Policy[60] of Enbridge Inc. (the parent company of Enbridge Gas) in relation to the proposed IRP Framework, and require it to do so. In reply, Enbridge Gas submitted that, in its view, the duty to consult was not triggered by the IRP proposal itself as the OEB's decision in this proceeding does not contemplate conduct that may adversely impact asserted or established Aboriginal or treaty rights.[61] Enbridge Gas also submitted that, regardless of whether the duty to consult has been triggered by this proceeding or whether Aboriginal consultation is required, Anwaatin has been a full participant in the current proceeding, and Enbridge Gas has carefully considered its views.

Going forward, Anwaatin requested that the OEB direct Enbridge Gas to conduct Indigenous-specific engagement in advance pursuant to each of the three stakeholdering components to ensure that there is an opportunity for Enbridge Gas to engage proactively in a considered and meaningful two-way dialogue with affected Indigenous communities.[62] Anwaatin also submitted that Enbridge Gas's stakeholder outreach and engagement process should demonstrate a stronger adherence and commitment to the Indigenous Peoples Policy, the United Nations Declaration on the Rights of Indigenous Peoples, and the duty to consult and accommodate.

In response to Anwaatin's submissions, Enbridge Gas submitted that it is committed to engaging with Indigenous peoples, in accordance with its Indigenous Peoples Policy and the duty to consult and accommodate, where applicable and where the procedural aspects have been delegated to Enbridge Gas. Enbridge Gas indicated that it would specifically consult with Indigenous communities with the potential to be affected by any IRPA investments selected, in accordance with the duty to consult.

Enbridge Gas also stated that it would follow the process for Indigenous consultation set out in the OEB's *Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario* (the Environmental Guidelines) for both facility and non-facility alternatives. OEB staff submitted that it was not clear whether all of the provisions of the Environmental Guidelines are a good fit for non-

[60] Available online at:
https://www.enbridge.com/~/media/Enb/Documents/About%20Us/indigenous_peoples_policy.pdf?la=en
[61] Enbridge Gas reply argument, pp. 15-16
[62] Anwaatin submission, pp. 14-19

facility alternatives (including the Indigenous consultation chapter of these Guidelines, which includes a significant role for the Ministry of Energy, Northern Development and Mines that may not apply to non-facility projects).[63]

Findings

The OEB does not find that Enbridge Gas failed to comply with the Indigenous People's Policy[64] of Enbridge Inc. The Enbridge Inc. policy limits the consultation to projects that may occur on lands traditionally used by Indigenous Peoples. More importantly, with respect to the duty to consult with Indigenous Peoples, the OEB's role is to determine if the duty has been triggered, and if so, whether the duty has been satisfied. It is not the OEB's role to enforce the implementation of a utility's internal policies that may not have been developed to satisfy external requirements.

Anwaatin submitted that the duty to consult is not limited to projects that have an immediate impact on land and resources but extends to "strategic, higher level decisions", such as the proposed IRP Framework. The OEB recognizes that the duty to consult may arise with respect to high-level managerial or policy decisions. However, this would require an identifiable potential adverse impact to an Aboriginal or treaty right. Neither Anwaatin, nor any other party, have identified any specific Aboriginal or treaty rights that could be adversely impacted through the creation of this IRP Framework.

In its decision in Enbridge Gas's RNG Enabling proceeding,[65] the OEB found that the duty to consult did not apply under the test set out in the Carrier Sekani case.[66] In coming to that conclusion, the OEB noted that there were no projects or even areas for future development being approved. Similarly, in this Decision and Order on the IRP Framework, no projects have been defined and no approval is being given for the

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[63] OEB staff argument, pp. 39-40
[64] Available online at: https://www.enbridge.com/~/media/Enb/Documents/About%20Us/indigenous_peoples_policy.pdf?la=en
[65] Application for the Renewable Natural Gas Enabling Program, EB-2017-0319, Decision and Order, October 18, 2018
[66] In *Carrier Sekani*, the Supreme Court of Canada summarized the three elements that are required for the Duty of Consult to be triggered. Briefly these are: the Crown must have real or constructive knowledge of a claim to the resource or land; there must be Crown conduct or a Crown decision that engages a potential Aboriginal right; the claimant must show a causal relationship between the proposed government conduct or decision and a potential for adverse impacts on pending Aboriginal claims or rights. *Rio Tinto Alcan Inc. v. Carrier Sekani Tribal Council*, 2010 SCC 43, paragraphs 40 to 45.

development of an IRP Plan. Once again, the OEB does not find any direct material impact that this Decision and Order will have on any Aboriginal or treaty rights.

The IRP Framework is being established by the OEB with input from many stakeholders including an Indigenous representative intervenor. Anwaatin has actively participated in this proceeding and made a submission on the issues and perspectives of Indigenous Peoples. The views presented have been heard and actively considered by the OEB.

Anwaatin also requested that the OEB direct Enbridge Gas to conduct Indigenous specific engagement in advance of each of the three IRP stakeholdering components to ensure that there is a meaningful two-way dialogue with affected Indigenous communities. The OEB finds this request to be too broad, and will not require Indigenous-specific engagement as a mandatory element for each of the three stakeholdering components in the IRP Framework in every case. Enbridge Gas has indicated that it will make efforts to accommodate participation of Indigenous groups within its stakeholder engagement process and work with these groups as appropriate to address any concerns. The OEB endorses this approach and expects that Indigenous engagement will take place in cases where material Indigenous interests are engaged.

There is insufficient information on the record at this time to determine which Indigenous communities would be impacted by specific system needs and the potential solutions (IRP Plans or facility projects), and what impact, if any, the individual IRP Plans might have on Aboriginal or treaty rights. In addition to any broader stakeholder engagement with Indigenous groups, Enbridge Gas is required to conduct consultation with respect to any potential impacts to Aboriginal or treaty rights in relation to proposed IRP Plans (which may include the individual IRPAs considered) and Leave to Construct applications. Any concerns can be considered on a case-by-case basis when an IRP Plan or a Leave to Construct application comes before the OEB for approval.

When Enbridge Gas requests approval for an IRP Plan or a Leave to Construct, it will be necessary for Enbridge Gas to follow the requirements in the Environmental Guidelines regarding Indigenous consultation, if applicable.

12 IRPA COST RECOVERY AND ACCOUNTING TREATMENT PRINCIPLES

Enbridge Gas requested approval of like-for-like treatment of IRPA investments, such that longer term investments in IRP Plans will be capitalized as rate base, with cost recovery similar to the facility investments that they are replacing at the time of in-service (with IRPA costs amortized over their useful lives).[67]

Enbridge Gas submitted that it is reasonable and appropriate to treat costs (capital expenditures and operating expenditures) associated with planning, implementing, administering, measuring and verifying the effectiveness of its investments in IRPAs in the same manner as the costs for the facility expansion/reinforcement projects that IRP would defer, avoid or reduce, by capitalizing these costs to rate base.

Enbridge Gas defined three categories of costs associated with IRP implementation and identified its proposed cost treatment for each category:[68]

- Incremental IRP administrative costs required to meet the increased workload related to IRP. Enbridge Gas proposed that incremental IRP administrative costs be included in the Operating, Maintenance, and Administrative (OM&A) costs of its revenue requirement. While Enbridge Gas indicated that it is difficult to say with certainty what additional resources will be required at this time to support IRP, Enbridge Gas estimated that it will need roughly 12 to 15 additional full-time equivalents to integrate IRP into its planning processes, complete the incremental stakeholdering, assess identified system constraints for IRPA(s), and complete necessary IRP Monitoring and Reporting.[69]

- IRPA Project costs including the planning, implementing, administering, measuring and verifying the effectiveness of specific investments in IRPAs. Enbridge Gas proposed that the IRPA project-related costs be capitalized to rate base, and eligible for cost recovery once a project is in-service.

- Ongoing operational and maintenance costs including the regular costs incurred to operate and maintain a specific IRPA investment after the project is in-service. Enbridge Gas proposed that the costs related to the ongoing operating maintenance of an IRPA be included in Enbridge Gas's OM&A costs of its

[67] Argument-in-Chief, p. 14
[68] Exhibit I.Staff.22
[69] Exhibit I.GEC.6

revenue requirement.

Enbridge Gas indicated that it believes existing accounting guidance is generally clear regarding the distinction of these cost categories, but that additional clarity could be sought if needed in the context of a specific IRP Plan application.[70] Enbridge Gas submitted that the details of which specific costs qualify to be treated as capital investments, and what asset life applies, could be addressed in an IRP Plan application. However, the IRP Framework should indicate the general principles that should apply to the cost treatment of IRP investments.

For some IRPAs, Enbridge Gas will make an investment in assets that it will own and operate, or programs that it will deliver. For other IRPAs, for example equipment or services available from the competitive market, Enbridge Gas will make an enabling payment to a service provider but will not own or operate any tangible asset. In those cases, Enbridge Gas proposed to treat the cost of the enabling payments or incentives made as a regulatory asset that would be added to rate base.[71] This could potentially apply to both demand-side and supply-side IRPAs. Enbridge Gas indicated that if capitalization might not be a workable approach for specific IRPAs (perhaps shorter-term solutions), it could bring forward an alternative accounting treatment within the context of an IRP Plan application.[72] Enbridge Gas acknowledged that its proposal to capitalize IRPA costs is different than the treatment of energy efficiency costs in the DSM Framework (which allows Enbridge Gas to recover costs on an annual basis with the possibility of a performance-based shareholder incentive, but does not include capitalization of costs) but submitted that this difference is appropriate because of the different purposes of DSM and IRP.

Enbridge Gas indicated that it follows U.S. Generally Accepted Accounting Principles (GAAP), which allows regulated entities to capitalize costs that would otherwise be expensed, if Enbridge Gas can demonstrate that it is probable that the costs will be recovered through future revenues derived from rates approved by the OEB (e.g. through a rate order). In this case, Enbridge Gas believes that regulatory rate base and audited financial statements would be aligned.[73]

Enbridge Gas indicated that it believes the cost recovery aspect of its IRP proposal could proceed independently of the ongoing OEB policy consultations on Utility

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[70] Technical Conference Transcript, Day 2, p. 205.
[71] Transcript from day 3 of oral hearing, pp. 37-41, Argument-in-Chief, p. 38
[72] Transcript from day 3 of oral hearing, pp. 104-108
[73] Exhibit J 3.7; Transcript from day 3 of oral hearing, pp. 145-147

Remuneration and Responding to Distributed Energy Resources.[74] On March 23, 2021, the OEB combined these consultations under the new title Framework for Energy Innovation (FEI): Distributed Resources and Utility Incentives (EB-2021-0118).[75] The OEB issued a letter about FEI after the record closed for this proceeding. This letter indicated that near-term workstreams will be focused on usage and integration of distributed energy resources, although the letter indicated that issues relating to utility remuneration would likely be considered in subsequent phases.[76]

Many parties supported the principle of Enbridge Gas's proposal for like-for-like cost treatment and agreed that this would remove a disincentive for Enbridge Gas to pursue IRP. Expert evidence from Guidehouse and EFG also supported the general principle of like-for-like treatment of IRPA investments. Guidehouse noted that Consolidated Edison in New York State is proposing a similar approach to capitalizing its future investments in IRPAs.

However, some parties argued that deciding on the capitalization treatment at this stage was premature, and that the OEB should wait until reviewing specific IRP Plan applications to decide on the capitalization treatment. Several parties indicated that their support for Enbridge Gas to earn a rate of return was conditional on the OEB's treatment of risk for IRP Plans. For example, CME proposed that ratepayers should only pay for investments from which they are deriving a benefit, and that the OEB could assess Enbridge Gas's potential recovery of those investments on the 'used and useful' test basis, to protect ratepayers from having to pay for unproductive or useless assets, if the IRP Plan did not deliver the benefits that were forecast.[77]

Several other parties (APPRO, LPMA, SEC) opposed Enbridge Gas's proposal and raised concerns that placing assets in rate base can create an unfair playing field with non-regulated providers of IRPAs. This concern was also raised in letters of comment submitted by the Ontario Geothermal Association and Diverso Energy, specifically with regard to the potential for Enbridge Gas to own and put into rate base geothermal systems as an IRPA.

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74 Technical Conference Transcript, Day 2, p. 206
75 Letter Re: Framework for Energy Innovation: Distributed Resources and Utility Incentives (EB-2021-0118), March 23, 2021
76 Letter Re: Framework for Energy Innovation: Distributed Resources and Utility Incentives (EB-2021-0118), May 10, 2021
77 CME Final Argument, pp. 18-21

SEC argued that normal accounting treatment for IRP costs should be followed, although exceptions could be granted on a case-by-case basis. SEC also noted that there was a potential risk of stranded assets applied to costs in rate base, for either IRPAs or facility projects. FRPO noted that while a utility company receives the benefits of being a monopoly provider with an opportunity to make a return on capital investments, there are utility costs that are incurred to provide safe and reliable service which are paid for in rates as expenses but do not generate additional return. FRPO indicated that solutions such as the Parkway Delivery Obligations have reduced facility investment and have been in place for years without Enbridge Gas receiving shareholder incentives or capitalization, and that capitalizing all IRPA costs would not be appropriate.

Enbridge Gas noted several objections to the suggestion that IRP costs should generally be expensed. First, it could lead to volatile rates, particularly in the first years of IRP implementation. Second, it could cause intergenerational inequity. Third, it ignores that other jurisdictions have adopted like-for-like treatment and capitalization of non-wires/non-pipes solutions. Finally, expensing IRP costs provides no incentive to the utility for pursuing IRP. When the utility engages in its traditional role of providing safe and reliable service, it is compensated for its capital investments. Enbridge Gas submitted that it is not a balanced approach to direct the utility to pursue alternate activities from those of its traditional role while at the same time indicating that there will be no compensation for pursuing the alternate activities that are being prescribed.

Additional/Alternative Incentive Mechanisms

The expert evidence of Guidehouse and EFG discussed the possibility of additional or alternative incentive mechanisms for Enbridge Gas to pursue IRP. Enbridge Gas indicated that it was open to considering additional incentives, but that it was not proposing such incentives as part of its IRP proposal, and that, in its view, the simplest way to create a level playing field between IRPAs and facility investment projects was to ensure that Enbridge Gas is equally incented between the two types of investments, through the proposed treatment to rate base IRPA costs. Should the OEB wish to prioritize investments in IRPAs, Enbridge Gas submitted that it could consider adding an incentive above rate of return (e.g. based on the net benefits achieved, in comparison with a facility project). However, this topic of incentives could be studied at a future date.[78]

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[78] Exhibit B, pp. 33-34, Exhibit I.Staff.25

Parties commenting on this topic generally did not support additional incentives for IRP, or felt it premature to include them in the IRP Framework at this time.

Enbridge Gas's position on incentives was tied to its proposal that it be eligible for recovery of all prudently incurred costs associated with IRPAs, and that ratepayers bear the performance risk associated with IRPAs. Enbridge Gas noted that, if the IRP Framework requires Enbridge Gas to bear additional risk associated with IRPAs, then Enbridge Gas would expect that commensurate adjustment to its allowed return on equity and/or incentives for such investments would be necessary to account for the heightened risk profile taken on by Enbridge Gas.[79]

Findings

The OEB finds that IRPA project costs, similar to the costs for infrastructure builds, should be eligible for inclusion in rate base where Enbridge Gas owns and operates the IRPA. Enbridge Gas should include in the project costs any physical assets acquired and costs directly attributable to the project consistent with how fixed assets are currently capitalized under US GAAP. Until rebasing, the associated revenue requirement of these project costs will be recorded in a capital costs deferral account for recovery annually or at rebasing as requested by Enbridge Gas.

Where Enbridge Gas proposes to make an enabling payment to a competitive service provider and does not own or operate the asset, these costs, if approved, will be included in the category of ongoing operational and maintenance costs and recovered as operating expenses. Notwithstanding concerns expressed about a potential unfair playing field with non-regulated providers of IRPAs, the OEB requires that Enbridge Gas select the most efficient and cost-effective option for its customers, between Enbridge Gas ownership and third-party ownership with an enabling payment. Until rebasing, these operating costs will be recorded in an operating costs deferral account for recovery annually or at rebasing as requested by Enbridge Gas. Incremental IRP administrative costs and other ongoing operational and maintenance costs will also be treated as expenses and recorded in this account.

The OEB finds that the inclusion in rate base for owned and operated IRPAs in this first-generation IRP Framework is preferred given its relative simplicity.

The consultations under the FEI are at an early stage with the development of terms of reference and initial meetings for the FEI working group. While the FEI consultation is

[79] Exhibit I.EP.6

likely to address matters of utility remuneration in subsequent phases, the first-generation IRP Framework will proceed before any determinations have been made. The OEB is therefore providing guidance on the approach to recovery of costs for the first-generation IRP Framework.

The IRPA project costs eligible for inclusion in rate base will attract the same cost of capital as other rate based assets for Enbridge Gas. The depreciation period for the IRPA assets will align with the expected useful life of the asset, which will likely be the time over which the underlying IRPA is expected to provide peak load reduction.

Details about how these principles will be applied to specific IRPAs and IRP Plans will be determined in the IRP Plan applications. As part of an IRP Plan application, Enbridge Gas should provide details on which IRP Plan costs it believes are eligible for inclusion in rate base, versus those that should be considered operating expenses, with supporting rationale. Details on recovery of IRP Plan costs through the IRP Costs deferral accounts, including the number of deferral accounts, elements to be included in the deferral accounts and method of recovery of approved deferral account costs are covered in chapter 15 (“IRP Costs Deferral Accounts”).

The OEB concludes that it is premature to develop an incentive mechanism or offer additional incentives as part of the first-generation IRP Framework. As more is learned though the pilots, the FEI, or experience in other jurisdictions, consideration of incentives may be part of the assessment of an IRP Plan on a case-by-case basis. This would require a detailed assessment of the risk of the IRPA compared to the risk premium already included in the approved return on equity.

13 FUTURE IRP PLAN APPLICATIONS

Enbridge Gas requested a new OEB approvals process, similar to the Leave to Construct approvals process used for facility projects, to review and approve a proposed IRP Plan designed to meet an identified need/constraint.[80]

Enbridge Gas indicated that it is seeking to establish similar assurances for investments in natural gas IRPA(s) as the OEB Act (under sections 90 and 91) affords natural gas utilities through Leave to Construct applications for facility projects, assuming associated costs of investment in IRPA(s) have been incurred prudently.[81]

Legal Basis for IRP Plan Approval and Required Information

Under section 90 of the OEB Act[82], an order from the OEB is required for leave to construct hydrocarbon pipelines that meet certain criteria relating to size, length, cost, or operating pressure. This legislative requirement is the basis for the existing Leave to Construct approval and parties agreed that it does not apply to IRP Plans.

Enbridge Gas indicated that the new IRP Plan approval could presumably be made under section 36 of the OEB Act, on the premise that the investments being made are in place of natural gas infrastructure and are aimed at ensuring that Enbridge Gas continues to provide safe, reliable gas delivery service to its customers. Section 36 of the OEB Act requires that sales of gas or charges for the transmission, distribution or storage of gas must be in accordance with an order of the OEB.

Enbridge Gas proposed to make IRP Plan applications to the OEB in the future in all instances where the total cost of IRP Plans exceeds the cost threshold that triggers a mandatory Leave to Construct approval for pipeline projects. This threshold is currently $2 million, although the Ontario government has proposed a change to the relevant regulation that would increase the threshold to $10 million.[83] IRP Plan applications below this threshold would be at Enbridge Gas's discretion, but Enbridge Gas indicated that it would likely seek OEB approval of all IRP Plans (including IRP pilot projects), at least in the initial stages of IRP.

[80] Argument-in-Chief, p. 14
[81] Argument-in-Chief, p. 41
[82] Section 91 of the OEB Act provides that before constructing a hydrocarbon line to which section 90 does not apply, an application may be made to the OEB for an order granting leave to construct.
[83] Environmental Registry Proposals 019-3041, 019-4029. The materiality threshold is specified in O.Reg. 328/03 under the OEB Act.

Enbridge Gas indicated that it expects that its IRP Plan application would include information similar to what is found in a Leave to Construct application, including purpose, need and timing type evidence (such as the forecast need/constraint being addressed, description of the IRPAs, forecast impacts from the IRPAs, costs of the IRPAs, and implementation timing), discussion of alternatives (why the IRP Plan was selected), land and environmental issues (where relevant), Indigenous consultation (as appropriate) and conditions of approval.[84] Enbridge Gas indicated that, while the IRP Plan approval would not itself be the mechanism for cost recovery, it might be appropriate for the OEB to invite submissions on Enbridge Gas's proposed cost allocation treatment within the IRP Plan approval process, because that could influence the positions of parties. Enbridge Gas proposed that the default cost allocation approach for an IRP Plan would generally be the same cost allocation approach as would have been used for the facility project that would otherwise have been needed.

Most commenting parties agreed with or did not oppose the proposal for a new IRP Plan approval and agreed that section 36 of the OEB Act provided the OEB with the necessary authority for this approval, particularly if (as recommended by OEB staff and APPRO) the application addressed issues such as the proposed approach to cost recovery and cost allocation and provided information on expected bill impacts. OEB staff also supported Enbridge Gas's proposal that the default approach to rate class allocation for an IRP Plan should be the same as would have been used for the facility project that would otherwise have been needed.

In its reply submission, Enbridge Gas agreed that this information should be included in an IRP Plan application, and submitted that the OEB could approve the cost consequences of a proposed IRP Plan under section 36 of the OEB Act, with that approval operating as an endorsement of the underlying IRP Plan.

Anwaatin disagreed, raising concerns that the IRP Plan approval is currently not authorized by sections 36, 90, 91, or 92 of the OEB Act.[85]

In addition to the information on cost recovery and cost allocation, OEB staff recommended adding a record of stakeholder and Indigenous groups engagement, as well as a proposed approach to evaluation and monitoring in each application for IRP Plan approval.

[84] Argument-in-Chief, pp. 40-41
[85] Anwaatin Inc. Final Argument, pp. 19-20

Adjustments to IRP Plans

Enbridge Gas requested flexibility to adjust an approved IRP Plan without further OEB review except where the costs being adjusted are 25% or greater of the total approved cost.

Several parties disagreed with this proposal. Energy Probe and APPRO suggested a lower cost overrun threshold was appropriate.

OEB staff supported providing Enbridge Gas with flexibility to adjust its investments in approved IRPAs, noting that this was consistent with the expert evidence filed by Guidehouse. Guidehouse recommended that the IRP Framework provide utilities with flexibility to adjust program designs, budgets, implementation plans, and other processes to quickly adapt IRP programs, and noted that this flexibility had been provided by the New York State Public Services Commission for Con Edison's Smart Solutions Program.[86]

However, OEB staff did not support the specific requirement for Enbridge Gas to return to the OEB when the costs being adjusted are 25% or greater of the original cost. OEB staff suggested that including this requirement as part of the Framework implied that cost increases that are less than 25% of the original cost would likely be approved when Enbridge Gas seeks cost recovery. OEB staff instead proposed that Enbridge Gas should have broad latitude to adjust its investments in approved IRP Plans, with the prudence of these adjustments to be reviewed when Enbridge Gas sought cost recovery. Under this approach, Enbridge Gas would always have the option of applying to the OEB to amend an approved IRP Plan if it wanted additional certainty regarding the likelihood of cost recovery.

Incrementality of IRP Plan Costs

OEB staff noted that some IRP Plans may be alternatives to facility projects that would have been implemented during the current deferred rebasing term, and as such, the associated costs would not necessarily be incremental, and would therefore not be eligible for cost recovery.

Enbridge Gas agreed that where an IRP Plan takes the place of a facility project that would have occurred during the current deferred rebasing term, then the associated costs are not necessarily entirely incremental (though they could be eligible for

[86] Guidehouse report, p. 17, 61

Incremental Capital Module treatment). However, Enbridge Gas submitted that where an IRP Plan takes the place of a facility project that would not have been implemented until after the end of the current deferred rebasing period, the associated IRP Plan costs are incremental and eligible for cost recovery in the future through the IRP Costs deferral account.

Findings

The OEB is establishing a new approval process for IRP Plans, as part of the IRP Framework. Regarding its approval authority, the OEB relies on section 36 of the *OEB Act* to approve the cost consequences of a proposed IRP Plan, with an IRP Plan approval operating as an endorsement of the underlying IRP Plan. The costs would then be recovered, subject to a prudence review, through the IRP Costs deferral accounts annually and/or at Enbridge Gas's next rebasing application, as discussed in more detail in chapter 15 ("IRP Costs Deferral Accounts").

OEB staff submitted that as Enbridge Gas gains more experience with IRPAs, it may be the case that an explicit IRP Plan approval would no longer be required, and Enbridge Gas's proposed spending on IRPAs could be reviewed solely within the context of Enbridge Gas's rate applications. The OEB agrees that there may be an evolution in the approval process as more experience is gained. However, the OEB finds that during this first-generation IRP Framework, it is appropriate to give Enbridge Gas assurance of preapproval of an IRP Plan to proceed. An IRP Plan approval will be mandatory if the forecast costs of the IRP Plan exceed the minimum project cost (currently $2 million, proposed to increase to $10 million) that would necessitate a Leave to Construct approval for a pipeline project. The OEB acknowledges that there may be a greater degree of uncertainty associated with IRP as a new activity, in comparison with facility projects, accordingly a preapproval of the IRP Plans is appropriate.

The OEB concludes that the information proposed by Enbridge Gas, with the additions proposed by OEB staff, and a section discussing how the guiding principles for the IRP Framework have been addressed, should be submitted with an IRP Plan approval request. Having a full understanding of not only the IRP Plan and its costs, but also about how those costs will be recovered and the resulting bill impacts, will be helpful to stakeholders and the OEB. The OEB expects that an approach to cost allocation will be part of an IRP Plan approval. The OEB agrees with Enbridge Gas that the approach to allocating costs for the facility project that is being avoided, deferred, or reduced by the IRP Plan will serve as an important reference point for the approach to cost allocation for IRP Plans.

As noted in chapter 12 (“IRPA Cost Recovery and Accounting Treatment Principles”), the information regarding cost recovery should include details on which IRP Plan costs Enbridge Gas proposes for inclusion in rate base, versus those that should be considered operating expenses, together with supporting rationale. This should also include a proposed in-service date, and any considerations that may apply regarding when the IRP Plan should be considered to be in-service such that Enbridge Gas is eligible for cost recovery.

Enbridge Gas proposed that whenever adjustments to an IRP Plan are expected to lead to cost differences of 25% or more of the total OEB approved costs for individual IRPA investments, then Enbridge Gas would apply to the OEB for approval to make the adjustments, but would otherwise have flexibility to adjust the IRP Plan without further OEB review. This flexibility is consistent with the recommendations of Guidehouse as well as its observations of flexibility offered to utilities in New York State. For this first-generation IRP Framework where there is less experience with IRPAs, the OEB agrees to the 25% threshold requirement for seeking approval of changes through an adjustment to an IRP Plan. When seeking recovery of actual IRP Plan costs, Enbridge Gas will need to demonstrate that it has been prudent in managing its actions and resulting costs, as is typical for all requests for cost recovery. As discussed in chapter 9 (“Allocation of IRP Risks”), Enbridge Gas will need to fully demonstrate the prudence of their actions particularly with regard to the risks of successful implementation of IRP Alternatives and the potential for assets becoming stranded.

As discussed in chapter 15 (“IRP Costs Deferral Accounts”), the OEB is establishing deferral accounts to record incremental costs associated with IRP, including IRP Plan costs, during the current deferred rebasing term. The OEB expects that an IRP Plan approval would address the issue of whether IRP Plan costs during this period are considered to be incremental. An IRP Plan application should identify whether Enbridge Gas intends to seek recovery of all or part of the IRP Plan costs, including Enbridge Gas’s rationale as to why these costs are incremental to activities included in existing rates. Whether there will be amendments to these deferral accounts after rebasing will be determined in the rebasing application, taking into consideration what IRP costs have been included in base rates.

The OEB expects that IRP Plan costs would qualify for recovery, subject to a prudence review, as part of the annual deferral account review or during the next rebasing application, The OEB acknowledges that IRP Plan costs may be eligible for recovery sooner than a facility project (unless the facility project met the criteria for an Incremental Capital Module). This is an incentive to encourage IRPA investments.

14 MONITORING AND REPORTING

Enbridge Gas requested approval of the proposed annual IRP reporting from Enbridge Gas that will address IRP integration into existing planning processes, IRPA effectiveness, IRP pilot projects planned or underway, IRP stakeholdering and IRPA implementation.[87]

Enbridge Gas proposed that the annual IRP report would include a summary of IRP stakeholdering, updates on IRP pilot projects, updates on incorporating IRP into AMP, status updates on potential and approved IRP Plans, and summaries of in-flight IRPAs, including expenditures and actual peak demand/energy savings compared to forecast.

Enbridge Gas indicated that the annual IRP report could be filed with the OEB as part of either its annual Rates application or Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application.

Most parties commenting on this issue agreed with the proposal for an annual IRP report and that the items were generally appropriate.

Several parties indicated that it was important that the annual IRP report be subject to stakeholder review, likely through an OEB proceeding. OEB staff suggested that the annual IRP Report be filed in the proceeding where Enbridge Gas proposes to clear the IRP Costs deferral account. Enbridge Gas agreed with that suggestion. Energy Probe requested that Enbridge Gas clarify whether the annual IRP report would be filed for information only or would be approved by the OEB. In reply, Enbridge Gas stated that stakeholders would have the opportunity to ask interrogatories about the annual IRP Report in the proceeding where it is filed, but that it is not necessary or appropriate for the OEB to issue an “approval” for the annual IRP Report. GEC submitted that an annual report from the Technical Working Group should also be part of the IRP reporting.

Several parties also commented on the issue of whether metrics or a scorecard for IRP should be part of the annual IRP reporting. Pollution Probe recommended that the OEB set an initial minimal set of scorecard metrics, while LPMA and APPRO suggested that metrics be established in the context of developing IRP Plans or pilot projects. In reply, Enbridge Gas submitted that it was premature to develop a scorecard or metrics for IRP activities in general, but that Enbridge Gas would not object to specific metrics to

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87 Argument-in-Chief, p. 15

monitor the performance of IRP Plans or pilot projects, which would be determined in an IRP Plan approval.

Findings

The OEB agrees with the key elements of the annual IRP Report proposed by Enbridge Gas including the following:

- A summary of IRP stakeholdering activities from the past year
- A summary of IRP engagement or consultation activities with Indigenous peoples
- Updates on IRP pilot projects underway
- Updates on incorporating IRP into asset management planning
- Updates on status of potential IRP Plans
- Updates on status of approved IRP Plans, including details of adjustments made by Enbridge Gas
- Annual and cumulative summaries of actual peak demand reductions/energy savings generated by each IRP Plan to-date, including comparisons to the initial forecast reduction/energy savings and the actual amount of expenditure on each IRP Plan to-date
- Any other IRP-related matters established by the OEB

As part of its update on incorporating IRP into asset management planning, or its update on the status of potential IRP Plans, Enbridge Gas should include the most recent results of its IRP Assessment Process for system needs, including reporting on those system needs where a negative binary screening or technical/economic evaluation resulted in no further assessment of IRPAs, as discussed in chapter 8 ("IRP Assessment Process"). Reporting from the Technical Working Group is discussed on chapter 10 ("Stakeholder Outreach and Engagement Process").

As discussed in chapter 7 ("Types of IRPAs"), the OEB has also determined that the annual IRP report should include a summary of best available information on demand-side IRPAs.

The OEB also requires that the annual IRP report provide information on any efforts taken to explore the use of interruptible rates for meeting system needs, including how customers have been provided the opportunity to consider this option.

The OEB finds that the proposed timing for submission of the annual IRP report as part of the proceeding where Enbridge Gas proposes to clear the IRP Costs deferral accounts (which will be Enbridge Gas's Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application) is appropriate, because it will assist in the consideration of the costs recorded in the IRP Costs deferral accounts, and will be an efficient approach. The annual IRP report and the report from the IRP Technical Working Group (discussed in chapter 10 ("Stakeholder Outreach and Engagement Process")) are to be filed for information regardless of whether Enbridge Gas is seeking approval to clear any balances in the IRP Costs deferral accounts.

The OEB does not intend to approve the annual IRP report. Any decisions with respect to the annual IRP Report in the immediate proceeding in which it is filed would be related to findings on the disposition of amounts in the deferral accounts. The annual IRP report could inform OEB decisions in future proceedings, including approvals for IRP Plans, adjustments above 25% to approved IRP Plans, approvals for Leave to Construct projects, or future iterations of the IRP Framework.

The OEB finds the suggested introduction of metrics or a scorecard for IRP is premature. For a subsequent period, the Technical Working Group should recommend metrics for the OEB's consideration.

15 IRP COSTS DEFERRAL ACCOUNTS

Enbridge Gas requested approval of an IRP Costs deferral account which will track all incremental IRP-related costs not included in base rates (capital, operating and administrative costs) during the current deferred rebasing term, for the years 2021, 2022, and 2023.[88] Enbridge Gas submitted that the costs of assessing, planning, stakeholdering, procuring, implementing, and evaluating the performance of IRPAs and IRP pilot projects are incremental costs not included in Enbridge base rates during the current deferred rebasing term.[89]

Enbridge Gas indicated that both incremental administrative costs and project costs associated with a specific IRP Plan (including IRP pilot projects) could be tracked in the IRP Costs deferral account.

Incremental IRP administrative costs, as discussed in chapter 12 ("IRPA Cost Recovery and Accounting Principles"), would include costs to integrate IRP into Enbridge Gas's planning processes, complete the incremental stakeholdering, assess identified system constraints for IRPAs, and complete necessary IRP Monitoring and Reporting. Enbridge Gas estimated that it will need roughly 12 to 15 additional full-time equivalents for these tasks.

Project costs for IRP Plans could include the planning, implementing, administering, measuring, and verifying the effectiveness of specific investments in IRPAs, as well as ongoing operational and maintenance costs including the regular costs incurred to operate and maintain a specific IRPA investment after the project is in-service.

Enbridge Gas proposed to seek clearance of the IRP Costs deferral account on an annual basis as part of its Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application.

Enbridge Gas expects to be rebasing its rates for the 2024 year. Enbridge Gas indicated that the IRP Costs deferral account may still be needed beyond 2023 to track IRP program costs not included in base rates in 2024 and through the next deferred rebasing term.

No party opposed the establishment of an IRP Costs deferral account, but OEB staff and several other parties expressed some concern that not all IRP-related costs may be

[88] Argument-in-Chief, p. 15
[89] Argument-in-Chief, p. 44

incremental. OEB staff submitted that if IRP Plans are being developed as alternatives to facility projects that would have been implemented during the current deferred rebasing term, then IRP Plan project costs may not be incremental, as they may be replacing activities that were already funded through rates. IGUA submitted that the establishment of a deferral account should not guarantee or predetermine the nature or quantum of costs.

Findings

The OEB approves the establishment of two IRP Costs deferral accounts for the period from 2021 to 2023. The OEB is establishing an IRP Operating Costs Deferral Account for all IRP OM&A costs that will be considered operating expenses, and an IRP Capital Costs Deferral Account for IRP Plan project costs that will be eligible for recovery of capital-related revenue requirement impacts. The IRP Operating Costs Deferral Account for the OM&A costs should include incremental general administrative IRP costs, and incremental ongoing evaluation, operating and maintenance costs for specific approved IRP Plans. As noted in chapter 12 (“IRPA Cost Recovery and Accounting Principles”), these costs would also include enabling payments to service providers that are part of IRP Plans.

IRP Plan project costs where Enbridge Gas owns and operates the IRPA will be eligible for inclusion in rate base with an associated capital-related revenue requirement. These project costs should be recorded in a tracking account (the IRP Capital Costs Deferral Account) that will facilitate the calculation of the revenue requirement consistent with US GAAP for these project assets.

The OEB is not requiring sub-accounts for specific IRP Plans, at least at this time. However, in both IRP Costs deferral accounts, Enbridge Gas should track costs at a sufficiently detailed level or category to assist in a prudence review of the costs incurred, which would include tracking costs at the level of each approved IRP Plan separately. If Enbridge Gas believes that sub-accounts would be useful to facilitate the approach to rate class allocation and disposition, this can be addressed as part of the IRP Plan application.

Costs in the IRP Operating Costs Deferral Account for general IRP administrative costs, may be brought forward for disposition without any prior approval. Costs in this account related to specific projects (e.g. project operating and maintenance costs, enabling payments to competitive service providers) should not be brought forward for disposition until an IRP Plan has been approved. When an IRP Plan has been approved and the project is considered to be “in-service”, Enbridge Gas is also eligible to seek cost recovery of the project's capital-related revenue requirement through the IRP Capital Costs Deferral Account.

The balances brought forward for disposition in the IRP Costs deferral accounts should be based on actual expenditures. The balance for the IRP Capital Costs Deferral Account will include the revenue requirement impacts associated with project costs eligible for inclusion in rate base. The application to clear any balance in the IRP Capital Costs Deferral Account should describe the reasons for any variance between actual costs and the forecast costs that were included in an IRP Plan approval.

The OEB agrees with OEB staff that the prudence of recorded costs and the extent to which IRP costs are incremental to existing operations or projects funded by rates can be determined at the time of clearance of the IRP Costs deferral accounts. The clearance of this account will also address the approach to allocating IRP costs by rate class. For costs associated with specific IRP Plans, incrementality and rate class allocation will be addressed as part of the IRP Plan approval, with the prudence of actual costs to be addressed at the time of clearance.

The OEB concludes that allowing Enbridge Gas to request recovery of balances that are eligible for disposition in the two IRP Costs deferral accounts either on an annual basis or at rebasing is appropriate. The OEB agrees that Enbridge Gas's Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application, which addresses disposition of the balances in a large number of deferral and variance accounts for Enbridge Gas on an annual basis, is an appropriate proceeding to address disposition of the balance in the IRP Costs deferral accounts.

The OEB directs Enbridge Gas to prepare a Draft Accounting Order for the two IRP Costs deferral accounts, consistent with the direction in this decision.

16 IRP PILOT PROJECTS

Enbridge Gas requested approval to develop and initiate two pilot projects by the end of 2022 – one of which will apply the new IRP Framework through development and implementation of an IRP Plan to meet an identified need/constraint (with an IRPA or combination of IRPAs to be determined) and the other of which will test a promising IRPA such as Demand Response, along with AMI, if possible.[90] Enbridge Gas indicated that the pilots would allow Enbridge Gas to test all or most of the components of the IRP proposal, from needs identification to binary screening to IRPA evaluation to project development and OEB approval to implementation and monitoring. Costs associated with pilot projects would be recorded in the proposed IRP Costs deferral account.[91]

Enbridge Gas indicated that it planned to engage with stakeholders and Indigenous groups before making a determination about what IRP pilot projects to pursue and also expected that the proposed Technical Working Group would provide input.

Enbridge Gas indicated that a reasonable timeline to identify, design, and deploy the IRP pilot projects would see initial steps beginning within three months of the issuance of the OEB's IRP Framework, with deployment by the end of 2022.

Enbridge Gas indicated that it would likely seek approval from the OEB for its proposed IRP pilot projects through IRP Plan applications.[92]

Enbridge Gas submitted that it may be appropriate to wait until information is gained through these pilot projects before proceeding to implement further IRP Plans.

As part of its evidence, Enbridge Gas also filed a report on a pilot project in Ingleside, Ontario, that assessed the impacts and costs of using geotargeted DSM to reduce peak demand, and tested the use of automated meter reading technology to collect and evaluate hourly demand data.[93]

There was widespread support and agreement by stakeholders that pilot projects would be an important and necessary component of the IRP Framework. In addition, evidence

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[90] Argument-in-Chief, p. 15
[91] Enbridge Gas also proposed that some of the funding for IRP pilot projects could potentially come from the balance in the Tax Variance Deferral Account. However, in its decision on the disposition of that account balance, the OEB denied that proposal. EB-2020-0134, Decision and Order, May 6, 2021, p. 11
[92] Argument-in-Chief, p. 40
[93] Enbridge Gas Reply Argument, Exhibit C, Appendix A, filed December 11, 2020

filed by all expert witnesses indicated that pilot projects had played an important role for other jurisdictions pursuing IRP (in the natural gas and electricity sectors).

Several parties provided suggestions as to how to improve learnings from the pilots. EFG's expert testimony (supported by ED and GEC) was that both Enbridge Gas's previous and proposed new pilots were too narrow, and a broader approach should be used to maximize learnings about IRP. EFG recommended that Enbridge Gas pursue multiple approaches (utility-run and procurement-driven) and multiple types of IRPAs.[94] OEB staff encouraged Enbridge Gas to consider EFG's suggestions, and also supported Enbridge Gas's comments that any future IRP pilot project should be sited in an area that includes a broader diversity of customer types and complexities so as to better test deployment. LIEN and VECC requested that Enbridge Gas situate IRP pilot projects in areas that include diverse customer types (including low-income customers).

In reply, Enbridge Gas indicated that it will be important to situate IRP pilot projects in areas that are representative of its service territory, taking into account where future system constraints are likely to be encountered. OSEA requested that the OEB consider requiring Enbridge Gas to prepare a summary report on Enbridge Gas's ongoing review of demand response pilot projects in other jurisdictions. Pollution Probe recommended one pilot based on targeted DSM, and one based on an alternative energy technology, with pilots to be undertaken in alignment with willing municipalities.

OEB staff submitted that the nature and details of the IRP pilot projects should be determined following consultation with stakeholders and the IRP Technical Working Group. OEB staff proposed that an application for approval of the IRP pilot projects be filed within 12 months of the issuance of the IRP Framework. In reply, Enbridge Gas indicated that it would aim to meet this proposed timeline, but was not able to commit, given uncertainties.

OEB staff did not support Enbridge Gas's proposal that it needs to wait for results from pilot projects before developing other IRP Plans, if Enbridge Gas determines that an IRP Plan is the best approach to meeting a system need with technologies and/or resources it is already familiar with, such as DSM.

SEC supported pilot projects and indicated that the pilots would inform Enbridge Gas's further consideration of IRP within its rebasing application. As a corollary, SEC submitted that the OEB should establish a moratorium on new facility projects between

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[94] Presentation to the OEB, Energy Futures Group, Presentation Day, February 19, 2021, pp. 29-30

now and rebasing, with the only exception being projects that Enbridge Gas can demonstrate are too urgent to wait for the rebasing application, and are not reasonably likely to be affected by IRP analysis.

In reply, Enbridge Gas clarified that it would identify and develop IRP Plans, but that it was too early to decide whether it would proceed to implementation, pending pilot results. Enbridge Gas disagreed with the moratorium on new facility projects proposed by SEC, stating that this would create a backlog in addressing constraints.

Findings

The OEB notes that there was universal support for Enbridge Gas's proposal to develop and implement two IRP pilot projects, and the OEB agrees with this approach. The pilots were seen as an effective approach to understand and evaluate how IRP can be implemented to avoid, delay or reduce facility projects. The use of pilot projects to better understand the development of IRP and IRPAs was generally used in other jurisdictions.

The OEB expects that the IRP pilot projects will be selected and deployed by the end of 2022 as proposed by Enbridge Gas. The detailed consideration of IRP pilot projects should commence shortly after the issuance of the IRP Framework with input being sought from the IRP Technical Working Group described in chapter 10 ("Stakeholder Outreach and Engagement Process").

The OEB finds that it is unnecessary for this decision to provide detailed direction on the pilot projects and recommends that the nature of the pilots should be responsive to the opportunities that arise. Enbridge Gas should then apply to the OEB for approval of the IRP pilot projects providing the information and following the approach described in the chapter 13 ("Future IRP Plan Applications").

While the OEB understands Enbridge Gas's reasoning behind waiting for the conclusion of the pilot projects before developing other IRP Plans, this should not be a barrier to addressing a system need through a non-pilot IRP Plan, if an exceptional time-limited opportunity arises prior to the completion of the pilots. The OEB does not agree with SEC that Enbridge Gas should defer all infrastructure builds until rebasing, when information from the pilots is available. The OEB shares Enbridge Gas's concern that this could create a backlog in addressing any constraints. The OEB also notes that the government of Ontario's policy concerning expansion of natural gas infrastructure to communities currently unserved by natural gas supports the ongoing construction of infrastructure builds in those communities.

Enbridge Gas should share key learnings from the pilots by reporting to the OEB and stakeholders through the annual IRP report, and more frequent updates to the IRP Technical Working Group, as needed. This experience will facilitate the development of other IRP Plans and identify areas for enhancement to the IRP Framework.

The IRP pilot project costs are to be tracked in the IRP Costs deferral accounts, and recovery can be requested annually for prudently incurred costs.

Enbridge Gas is encouraged to use the IRP pilot projects as a testing ground for an enhanced DCF+ test as discussed in section 8.3 (“Two-Stage Evaluation Process”).

17 AMI ACKNOWLEDGEMENT

Enbridge Gas requested that the IRP Framework include an indication of the OEB's support for the role of Advanced Metering Infrastructure (AMI) as an important enabler of successful IRP and IRPAs.[95] As defined by Enbridge Gas, AMI is an integrated system of meters, end points, communications networks, and data management systems that enables two-way communication between utilities and customer meters. AMI would enable more frequent data collection of actual gas consumption at the customer level (e.g., hourly data instead of monthly).

Enbridge Gas indicated that AMI will allow for the collection of the hourly data that it requires to not only target IRPAs effectively but also to monitor and verify their effectiveness to ensure that the IRPAs are performing as expected and to ensure peak period demand reductions are materializing. Without AMI, Enbridge Gas indicated that it will need to rely on system modelling to assess IRPAs, which will drive the need to overbuild the IRPA, as well as robust additional evaluation, measurement, and verification work, both of which drive up costs for IRPA(s).[96]

Enbridge Gas did not request approval for AMI funding within this proceeding but indicated that it is considering requesting broad deployment of AMI in the future in a separate proceeding, likely its 2024 rebasing application.[97] Enbridge Gas also indicated that it may request approval to target key geographic areas for AMI deployment where future constraints are identified and where AMI might be useful in evaluating IRPAs' effectiveness.

Most parties (with the exception of OSEA) did not support Enbridge Gas's request that AMI be noted as an important enabler of IRP, although several acknowledged that AMI could provide information that would be valuable in IRP implementation.

Parties submitted that Enbridge Gas had not provided sufficient evidence or a compelling business case for AMI and expressed concerns that an endorsement of AMI would be premature, particularly if it influenced specific AMI-related funding requests which Enbridge Gas might make to the OEB in the future.

Parties also noted that other monitoring solutions, such as metering at strategic points in the distribution system, may be preferable or more cost-effective than metering at the

[95] Argument-in-Chief, p. 15
[96] Exhibit B, pp. 35-36. See also Exhibit I.Staff.4(f)
[97] Argument-in-Chief, pp. 47-49

level of individual customers, depending on the specifics of an IRP Plan. OEB staff submitted that the expected benefits of monitoring and metering technologies to enable more effective consideration, implementation, and evaluation of IRPAs in meeting system needs should be considered along with their costs.

Several parties commented that pilot projects could be used to assess the value of AMI, which could include an approach comparing IRP with and without AMI.

Findings

The OEB concludes that there is insufficient information to determine if AMI is a cost-effective enabler of IRP and IRPAs such as demand response. Using the more conservative derating factors (or IRPA oversubscription) that Enbridge Gas proposed during this early stage of IRP might be a more efficient way to gain experience and ensure that peak period demand reductions are achieved. Metering at strategic points in the distribution system, as suggested by several parties, might also be worth exploration. Enbridge Gas can provide a business case with additional rationale for AMI, either as part of a specific IRP Plan application, or as part of its next rebasing application.

18 IMPLEMENTATION

A final "Integrated Resource Planning Framework for Enbridge Gas" is attached as Appendix A to this Decision and Order. The Framework is a companion document to this Decision and Order regarding IRP for Enbridge Gas. Enbridge Gas is expected to begin integrating IRP into its existing planning processes, in a manner consistent with the IRP Framework, effective immediately.

Specific milestones for Enbridge Gas in the IRP Framework include:

- Filing an annual IRP report as part of its Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application
- Filing its first version of the Asset Management Plan reflecting the updated IRP Assessment Process in Fall 2022
- Selecting and deploying IRP pilot projects by the end of 2022
- As part of its next rebasing application, filing a study on interruptible rates to determine how they might be modified to increase customer adoption of this alternative service in order to help reduce peak demand
- As part of its next rebasing application, filing an analysis of the historical accuracy of Enbridge Gas's demand forecast, as required by section 2.3.2 of the Filing Requirements for Natural Gas Rate Applications

In addition, OEB staff shall establish the IRP Technical Working Group, including a terms of reference and the initial selection of Technical Working Group members, by the end of 2021. The OEB expects that the first priorities of the Technical Working Group will be the IRP pilot projects, and enhancements or additional guidance in applying the DCF+ evaluation methodology in the context of IRP.

Enbridge Gas shall file a draft accounting order for the establishment of the IRP Operating Costs Deferral Account, and IRP Capital Costs Deferral Account as described in chapter 15 ("IRP Costs Deferral Accounts").

The OEB has also scheduled a process for intervenor costs.

19 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. The guidance provided in this Decision and Order, including the document “Integrated Resource Planning Framework for Enbridge Gas” in Appendix A, is effective immediately.

2. Enbridge Gas Inc. shall file a draft accounting order for the IRP Costs deferral accounts consistent with this Decision and Order by **August 12, 2021**.

3. OEB staff and intervenors may file any comments on the draft accounting order by no later than **August 26, 2021**. No cost awards will be granted for this procedural step.

4. Intervenors shall file with the OEB, and forward to Enbridge Gas Inc., their respective cost claims by **August 26, 2021**.

5. Enbridge Gas Inc. shall file with the OEB, and forward to intervenors, any objections to the claimed costs by **September 9, 2021**.

6. Intervenors shall file with the OEB, and forward to Enbridge Gas Inc., any responses to any objections for cost claims by **September 16, 2021**.

7. Enbridge Gas Inc. shall pay the OEB’s costs incidental to this proceeding upon receipt of the OEB’s invoice.

Parties are responsible for ensuring that any documents they file with the OEB, such as applicant and intervenor evidence, interrogatories and responses to interrogatories or any other type of document, **do not include personal information** (as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*), unless filed in accordance with rule 9A of the OEB’s Rules of Practice and Procedure.

Please quote file number, **EB-2020-0091** for all materials filed and submit them in searchable/unrestricted PDF format with a digital signature through the OEB’s online filing portal.

- Filings should clearly state the sender's name, postal address, telephone number and e-mail address
- Please use the document naming conventions and document submission standards outlined in the Regulatory Electronic Submission System (RESS) Document Guidelines found at the Filing Systems page on the OEB's website
- Parties are encouraged to use RESS. Those who have not yet set up an account, or require assistance using the online filing portal can contact registrar@oeb.ca for assistance

All communications should be directed to the attention of the Registrar at the address below and be received by end of business, 4:45 p.m., on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Michael Parkes at michael.parkes@oeb.ca and OEB Counsel, Michael Millar at michael.millar@oeb.ca.

Email: registrar@oeb.ca

Tel: 1-877-632-2727 (Toll free)

DATED at Toronto July 22, 2021

ONTARIO ENERGY BOARD

Original Signed By

Christine E. Long
Registrar

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

July 22, 2021

Integrated Resource Planning Framework for Enbridge Gas

EB-2020-0091 (Appendix A)

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1 INTRODUCTION AND PURPOSE

This document describes the first-generation Integrated Resource Planning (IRP) Framework for Enbridge Gas. Within the energy sector generally, integrated resource planning usually refers to a planning process that evaluates and compares both supply-side and demand-side options to meeting an energy system need, and may also refer to consideration of multiple energy sources, and co-ordination or integration between multiple energy service providers. A definition of IRP specific to Enbridge Gas's operations is provided in chapter 2 ("Definitions").

This IRP Framework is a companion document to the OEB's July 22, 2021 Decision and Order on Enbridge Gas's Integrated Resource Planning proposal (EB-2020-0091), regarding IRP for Enbridge Gas. While the IRP Framework is intended to be fully consistent with the Decision and Order, in case of any discrepancy, the wording in the Decision and Order will prevail. The expectation is that enhancements and improvements will be made in the future on the basis of the experience gained in Ontario with pilot projects and other IRP activities, drawing on successes achieved in other jurisdictions, and future policy direction.

The IRP Framework provides direction to Enbridge Gas on topics to be covered in an IRP Plan (defined in chapter 2 ("Definitions")), and the OEB's requirements as Enbridge Gas considers IRP to meet its system needs. If Enbridge Gas has reasons for a specific IRP Plan to deviate from the IRP Framework, it should justify why deviations from the Framework requirements are appropriate.

The IRP Framework has been established for Enbridge Gas; however, it should also be used as a resource to guide EPCOR Natural Gas Limited Partnership when it examines infrastructure investments and potential alternatives.

2 DEFINITIONS

The following terms are defined in the IRP Framework:

- **Integrated Resource Planning:** A planning strategy and process that considers Facility Alternatives and IRP Alternatives (including the interplay of these options) to address the system needs of Enbridge Gas's regulated operations, and identifies and implements the alternative (or combination of alternatives) that is in the best interest of Enbridge Gas and its customers, taking into account reliability and safety, cost-effectiveness, public policy, optimized scoping, and risk management.

- **IRP Assessment Process:** The process used by Enbridge Gas to determine the preferred solution to meet specific system needs, including consideration of Facility Alternatives and IRP Alternatives.

- **Facility Alternative:** A potential infrastructure solution considered under the IRP Assessment Process in response to a specific system need of Enbridge Gas. In this IRP Framework, the term is synonymous with a traditional or conventional facility project. This would typically include a hydrocarbon line (as defined in the *OEB Act*) developed by Enbridge Gas, and ancillary infrastructure. Facility Alternatives determined by Enbridge Gas to be the preferred solution to meet the system need will often require approval from the OEB through a Leave to Construct application. For clarity, non-traditional solutions to system needs that include infrastructure developed by Enbridge Gas, such as injection of compressed or renewable natural gas, or storage of natural gas within the distribution or transmission system, are considered to be IRP Alternatives and not Facility Alternatives.

- **IRP Alternative (IRPA):** A potential solution other than a Facility Alternative considered in Enbridge Gas's IRP Assessment Process in response to a specific system need of Enbridge Gas. IRPAs determined by Enbridge Gas to be the preferred solution to meet the system need (alone, in combination with other IRPAs, or in combination with a Facility Alternative) would likely be brought forward for approval from the OEB through an IRP Plan.

- **IRP Plan:** A plan filed by Enbridge Gas for OEB approval in response to a specific system need, that includes one or more IRPAs.

3 GUIDING PRINCIPLES

The OEB has adopted the following guiding principles for IRP. IRP Plans filed with the OEB should include a section to discuss how these guiding principles have been addressed.

- Reliability and safety – In considering IRPAs as part of system planning processes, Enbridge Gas's system design principles cannot be compromised, and the reliable and safe delivery of firm contracted peak period natural gas volumes to Enbridge Gas's customers must remain of paramount importance.

- Cost-effectiveness – IRPAs must be cost-effective (competitive) compared to Facility Alternatives and other IRPAs, including taking into account impacts on Enbridge Gas customers.

- Public policy – IRP will be considered in a manner to ensure that it is supportive of and aligned with public policy, and in particular the OEB's statutory objectives for the natural gas sector.

- Optimized scoping – Recognizing that reviewing IRPAs for every forecast infrastructure project would be extremely time intensive, binary screening should be undertaken, to confirm which forecast need(s) should undergo evaluation of IRPAs, and to ensure a focus at the outset on efficient and effective IRPA investment.

- Risk management – Economic risks associated with both Facility Alternatives and IRPAs in meeting system needs are evaluated and appropriately mitigated. Risks and rewards are allocated appropriately between Enbridge Gas and its customers.

4 TYPES OF IRPAS

Demand-side programming may include IRPAs such as geotargeted energy efficiency programs, and demand response programs (which incent or oblige the customer to reduce or shift energy usage during peak periods). Demand-side IRPAs are expected to target specific constrained areas and (amongst other things) encourage customers to reduce peak consumption.

Interruptible rates can also be used to reduce peak demand. While approval of interruptible rates would be considered in a rebasing rate application, the impact of interruptible rates to meet a system need/constraint should be considered in an IRP Plan in combination with demand-side or supply-side alternatives.

Supply-side IRPAs could include injection of compressed natural gas into the pipeline system in a constrained area, or renewable natural gas sourced within the constrained area. Supply-side IRPAs may also include market-based supply side alternatives. This could include contractual arrangements requiring delivery of natural gas to specific points on Enbridge Gas's system that harness the capability of existing pipeline infrastructure (including non-Enbridge Gas pipelines) to avoid or defer the need for Enbridge Gas to build new pipeline infrastructure.

As part of this first-generation IRP Framework, the OEB has determined that it is not appropriate to provide funding to Enbridge Gas for electricity IRPAs. Enbridge Gas can seek opportunities to work with the Independent Electricity System Operator or local electricity distributors to facilitate electricity-based energy solutions to address a system need/constraint, as an alternative to IRPAs or facility projects undertaken by Enbridge Gas. The OEB is not establishing this as a requirement.

For both demand-side and supply-side IRPAs, Enbridge Gas should look to procure equipment or activities through the competitive market, where feasible and cost-effective.

Enbridge Gas should consider both combination IRP Plans (that may include multiple supply-side or demand-side IRPAs or an IRPA in combination with a Facility Alternative) and bridging solutions in its IRP assessment process if the bridging solution provides the best alternative in the near term, while exploring longer term solutions.

To support the analysis of IRPAs and promote more timely development of IRP Plans, Enbridge Gas shall provide a document on best available information for demand-side

IRPAs. This will be provided with Enbridge Gas's annual IRP report discussed in chapter 10 ("Monitoring and Reporting").

5 IRP ASSESSMENT PROCESS

Enbridge Gas will use a four-step IRP Assessment Process to determine the best approach to meeting system needs, including whether to pursue IRPAs for an identified need/constraint. In a project-specific application (Leave to Construct or IRP Plan), Enbridge Gas is required to demonstrate that it has followed this process including the results of the analysis at each stage of the process.

1. Identification of Constraints

2. Binary Screening Criteria

3. Two-Stage Evaluation Process

4. Periodic Review

The OEB expects that Enbridge will integrate its IRP Assessment Process into its annual planning.

Within its annual IRP report, Enbridge Gas shall report on the results of its IRP Assessment Process, including reporting on those system needs where a negative result at step two (binary screening) or step three (technical/economic evaluation) resulted in a determination by Enbridge Gas for no further assessment of IRPAs.

5.1 IRP Assessment Process Step 1: Identification of Constraints

Enbridge Gas shall identify potential system needs/constraints up to ten years in the future, and describe these in annual updates to the Asset Management Plan (AMP) to allow time for a detailed examination of IRPAs. The AMP is currently filed each year as part of Enbridge Gas's rate adjustment proceedings. The AMP process addresses all utility assets within Enbridge Gas's regulated operations.

An updated version of the AMP will be filed each year. The information filed within each AMP should include:

- a list of identified system needs
- the status of IRP Plan consideration for each system need
- the result of the initial binary screening
- details as to whether and why IRP Plans have been screened out at subsequent steps, with supporting rationale

- any material changes to the demand forecast, relative to the demand forecast that was assessed as part of the last rebasing application

The OEB expects that, for projects brought to the OEB for approval (both Leave to Construct projects and IRP Plans), the system need will have previously been identified in the AMP (although the preferred project to meet the system need may not have been determined at that time). For any previously unidentified needs, Enbridge Gas will need to provide an explanation as to why the project is needed at this time.

5.2 IRP Assessment Process Step 2: Binary Screening Criteria

The IRP Framework will include screening criteria, in order to focus on those situations where there is a reasonable expectation that an IRPA could efficiently and economically meet the system need.

Enbridge Gas will apply these binary screening criteria to identified system needs/constraints (as identified in step 1) to determine whether further IRP evaluation is appropriate. Binary screening would thus exclude some system needs from further IRP consideration. System needs where IRP is not screened out through this binary screening would next move to the two-stage IRP evaluation process.

The OEB has established the following screening criteria for the first-generation IRP Framework.

<u>Emergent Safety Issues</u>

The first criterion deals with urgent or imminent issues. The safety and reliability of the gas system is paramount. Removing constraints that jeopardize this system performance does not allow time for the development and assessment of an IRP Plan.

i. ***Emergent Safety Issues*** *– If an identified system constraint/need is determined to require a facility project for Enbridge Gas to offer safe and reliable service or to meet an applicable law, an IRP evaluation is not required. An example of such a system constraint/need, and an emergent safety issue, would be if an existing pipeline sustained unanticipated damage and needed to be replaced as quickly as possible to ensure the safety of local communities and Enbridge Gas's broader transmission and distribution systems. Longer-term safety related system constraints/needs may be appropriate for an IRP Plan and should be considered on a case-by-case basis.*

Timing

It takes time to assess and implement an IRP Plan along with demonstration that the constraint is being mitigated. Once a ten-year AMP consistent with the IRP Framework has been in place for several years, there should be fewer situations where a timing criterion is needed; however, for this first-generation IRP Framework, the OEB is establishing a timing criterion. The use of supply-side options might be possible to meet an identified need within a shorter period.

ii. ***Timing*** *– If an identified system constraint/need must be met in under three years, an IRP Plan could not likely be implemented and its ability to resolve the identified system constraint could not be verified in time. Therefore, an IRP evaluation is not required. Exceptions to this criterion could include consideration of supply-side IRPAs and bridging or market-based alternatives where such IRPAs can address a more imminent need.*

Customer-Specific Builds

Where the customer fully pays for the incremental infrastructure costs associated with a facility project, in the form of a Contribution in Aid of Construction, consideration of an IRP Plan is not required.[1] However, Enbridge Gas is encouraged to discuss demand-side management (DSM) opportunities with customers to potentially reduce the size of the build.

iii. ***Customer-Specific Builds*** *– If an identified system need has been underpinned by a specific customer's (or group of customers') clear request for a facility project and either the choice to pay a Contribution in Aid of Construction or to contract for long-term firm services delivered by such facilities, then an IRP evaluation is not required.*

Community Expansion & Economic Development

Given the goal of the Ontario Government's Access to Natural Gas legislation[2] to extend gas service to designated communities, Enbridge Gas is not required to develop an IRP Plan or consider alternatives to the infrastructure facilities to meet this need. However, Enbridge Gas is encouraged to discuss DSM opportunities with customers to potentially reduce the size of the build.

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[1] The incremental costs recovered through a Contribution in Aid of Construction are set at an amount that reduces the capital cost of a project for Enbridge Gas ratepayers such that the project becomes economically feasible, which generally requires a profitability index greater than or equal to one.
[2] *Access to Natural Gas Act, 2018*, S.O. 2018, c. 15 - Bill 32

iv. ***Community Expansion & Economic Development*** *– If a facility project has been driven by government legislation or policy with related funding explicitly aimed at delivering natural gas into communities, then an IRP evaluation is not required.*

<u>Pipeline Replacement and Relocation Projects</u>

A minimum cost of the facility project that would be built to meet a system need (in the absence of IRP) is required to justify the time and effort to conduct an IRP evaluation and potentially develop an IRP Plan. Projects under $2 million should be screened out unless the government makes regulatory changes establishing a $10 million threshold for OEB Leave to Construct approvals, in which case, the criteria should use $10 million to determine if an IRP evaluation is appropriate.

v. ***Pipeline Replacement and Relocation Projects*** *– If a facility project is being advanced for replacement or relocation of a pipeline and the cost is less than the minimum project cost that would necessitate a Leave to Construct approval, then an IRP evaluation is not required.*

5.3 IRP Assessment Process Step 3: Two-Stage Evaluation Process

For system needs progressing past the initial IRP binary screening, Enbridge Gas will determine whether to proceed with an IRP Plan through a two-stage evaluation. First, Enbridge Gas will determine whether potential IRPAs could meet the identified constraint/need. If yes, then Enbridge Gas will compare one or more IRP Plans to the baseline Facility Alternative, using a Discounted Cash Flow-plus (DCF+) economic test, to determine the optimum solution to meet the system need. It is expected that the two-stage evaluation process would commence sufficiently far in advance of the date that the constraint/need must be met in order to allow for time for an IRP Plan to be developed, approved, implemented and monitored for effectiveness in advance of the date when a facility project would be required.

Stage 1: Technical Evaluation

The first stage will look at the technical viability of potential IRPAs to reduce peak demand to the degree required to meet the identified system need, using best available information (including information on IRPAs from Enbridge Gas's annual IRP report), to determine whether an IRP Plan including one or more IRPAs would be a viable option. Enbridge Gas may use derating factors (i.e., assuming less than 100% of the forecast peak demand reduction from the IRPAs would be delivered) or oversubscription of IRPAs to address uncertainty regarding forecast savings. These derating factors may be relevant to both the technical and economic evaluations. In any subsequent application for OEB approval of specific IRP Plans, Enbridge Gas should identify both the level of oversubscription and the supporting rationale.

Stage 2: Economic Evaluation

The economic evaluation used to compare the IRP Plan(s) to the baseline Facility Alternative will consist of a three-phase DCF+ evaluation, including a focus on rate impacts, as identified in phase 1 of the DCF+ test.

The DCF+ test will be based on the three-phase economic test that Enbridge Gas is required to use to assess the costs and benefits of potential transmission system expansions, under the parameters established by the *Report of the Board on the Expansion of the Natural Gas System in Ontario* (the E.B.O. 134 report). The principles of this test are summarized in the OEB's *Filing Guidelines on the Economic Tests for Transmission Pipeline Applications*. In the IRP Framework, the DCF+ test will include the following phases:

- Phase 1 assesses the economic benefits and costs from the utility perspective, and indicates whether the project is likely to result in future increases to utility rates.
- Phase 2 assesses the incremental economic benefits and costs incurred by customers from the IRP Plan(s) or Facility Alternative(s).
- Phase 3 assesses the incremental societal benefits and costs.

A Net Present Value will be calculated for each phase. Results from each phase will be presented separately for transparency, but will also be summed together.

The DCF+ results for the IRP Plan(s) and the baseline Facility Alternative will be compared to one another to determine which alternative is optimal. IRP Plans that included some combination of IRPA and facility project can also be tested using this approach.

Enbridge Gas has some discretion to select an alternative to meet a system need that does not have the highest score on phase 1 of the DCF+ test, as there may be considerations or factors that are important in phases 2 or 3, or are difficult to quantify. However, this will require justification if Enbridge Gas recommends a higher cost alternative.

The OEB accepts the categories of benefits and costs proposed by Enbridge Gas for the three phases of the DCF+ test (shown in Table 1) for the use of this test in the IRP Framework.

Table 1: Discounted Cash Flow-Plus Test Costs and Benefits

Benefit/Cost	Phase 1	Phase 2	Phase 3
Benefits			
Incremental Revenues	x		
Avoided Utility Infrastructure Costs [2]	x		
Avoided Customer Infrastructure Costs [3]		x	
Avoided Utility Commodity/Fuel Costs [4]	x		
Avoided Customer Commodity/Fuel Costs [5]		x	
Avoided Operations & Maintenance	x		
Avoided Greenhouse Gas Emissions		x	
Other External Non-Energy Benefits			x
Costs			
Incremental Capital Expenditure [1]	x		
Incremental Operations & Maintenance [1]	x		
Incremental Taxes	x		
Incremental Utility Commodity/Fuel Costs [4]	x		
Incremental Customer Commodity/Fuel Costs [5]		x	
Incremental Greenhouse Gas Emissions		x	
Incremental Customer Costs		x	
Other External Non-Energy Costs			x

Notes:
(1) Capital and Operations & Maintenance is inclusive of program administrative costs
(2) Avoided or reduced infrastructure capital costs of the utility (e.g., 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)

Further work will be needed to refine the use of the DCF+ test in the context of IRP. The DCF+ test could be improved to better list and define the costs and benefits of Facility Alternatives and IRPAs, and clarify how these costs and benefits should be considered within the DCF+ test. This could include expanding the inputs to recognize increasing carbon costs, the risk that a constraint remains unresolved, and impact on gas supply costs. Enbridge Gas shall study improvements to the DCF+ test for IRP, and is encouraged to consult with the IRP Technical Working Group and to use the IRP pilot projects as a testing ground for an enhanced DCF+ test. In particular, the IRP Technical Working Group should consider how different carbon pricing scenarios should be used in the DCF+ calculation. The OEB directs that Enbridge Gas file an enhanced DCF+ test for approval as part of the first non-pilot IRP Plan.

5.4 IRP Assessment Process Step 4: Periodic Review

Material changes may occur that could impact Enbridge Gas's determination as to how best to meet a system need. These may include changes occurring when implementing an IRP Plan after receiving project approval. Examples could include where the nature or timing of an identified need/constraint alters materially, or significant policy changes are announced by government or the OEB. In such cases, Enbridge Gas may review its IRP determinations, and may choose to discuss with the IRP Technical Working Group.

Updates of this nature should be provided by Enbridge Gas as part of its annual IRP report. If Enbridge Gas plans to increase its spending on an approved IRP Plan by more than 25%, it will need to request OEB approval for the change, as discussed in chapter 9 ("Future IRP Plan Applications").

6 STAKEHOLDER OUTREACH AND ENGAGEMENT PROCESS

6.1 Stakeholder Engagement Process

Enbridge Gas is required to use a three-component stakeholder engagement process to provide input into its IRP activities.

The three components will involve:

1. Gathering of Stakeholder Engagement Data and Insight: Seeking insights from stakeholders and various market participants by working within existing stakeholder engagement channels, on an ongoing basis, to mitigate incremental expenses and leverage existing relationships.
2. Stakeholder Days: Annual regional stakeholder events focused on IRP to discuss plans and progress with IRP, including specific discussion of needs/constraints identified in the AMP and the plans to address such items through IRP. These would be held on an annual basis shortly after Enbridge Gas files its AMP update within Phase 2 of the annual rates proceeding.
3. Targeted Engagement: Project-specific consultation dealing with specific IRPAs or IRP Plans (identified for a specific need in a specific geographic region), with stakeholders from the specific geographic area relevant to the IRPA. Project-specific consultation must be done in advance of seeking project approval from the OEB.

It is expected that Enbridge Gas will record comments from stakeholders and Indigenous groups participating in components 2 and 3 and the responses from Enbridge Gas to these comments. This information is to be filed in any subsequent IRP Plan/Leave to Construct application. Chapter 7 (“Indigenous Engagement and Consultation”) provides additional details on Indigenous engagement and consultation.

Enbridge Gas shall also establish a website to facilitate the broad sharing of information on IRP stakeholdering efforts.

6.2 Technical Working Group

In addition to the three-component stakeholder process, the OEB is establishing an IRP Technical Working Group led by OEB staff, similar to the Demand-Side Management Evaluation Advisory Committee. OEB staff will establish a terms of reference and select the membership. Establishment of the IRP Technical Working Group, including a terms of reference, and the initial selection of working group members, shall be done by the end of 2021.

The IRP Technical Working Group has an objective of providing input on IRP issues that is of value to both Enbridge Gas in implementing IRP, and to the OEB in its oversight of the IRP Framework.

The OEB expects that the first priorities of the IRP Technical Working Group will be:

- Consideration and implementation of IRP pilot projects
- Enhancements or additional guidance in applying the DCF+ evaluation methodology

Additional topics to be examined by the IRP Technical Working Group could include:

- Learnings from IRPAs and IRP implementation in other jurisdictions
- Developing IRP performance metrics for the OEB's consideration
- Treatment of stranded assets in other jurisdictions

The IRP Technical Working Group will also be expected to review a draft of Enbridge Gas's annual IRP report, with the review coordinated by OEB staff. Enbridge Gas should provide a draft of the annual IRP report to the IRP Technical Working Group far enough in advance of its planned filling to the OEB to allow the Technical Working Group time to review and comment. A report from the Technical Working Group to the OEB should be filed by OEB staff in the same proceeding in which Enbridge Gas's annual IRP report is filed. The Technical Working Group report should include any comments on Enbridge Gas's annual IRP report, including material concerns that remain unresolved within the Technical Working Group, and may also describe other activities undertaken by the Technical Working Group in the previous year.

As the natural gas system operator, Enbridge Gas retains the sole responsibility to make final system planning decisions and to advance IRP Plans and/or Leave to Construct applications. While Enbridge Gas is expected to consider any input provided by the IRP Technical Working Group, the IRP Technical Working Group will not have "voting rights" that bind Enbridge Gas with regards to its system planning decisions.

7 INDIGENOUS ENGAGEMENT AND CONSULTATION

Enbridge Gas will make efforts to accommodate participation of Indigenous groups within its stakeholder engagement process and work with these groups as appropriate to address any concerns. The OEB endorses this approach and expects that Indigenous engagement will take place in cases where material Indigenous interests are engaged.

In addition to any broader stakeholder engagement with Indigenous groups, Enbridge Gas is required to conduct consultation with respect to any potential impacts to Aboriginal or treaty rights in relation to proposed IRP Plans (which may include the individual IRPAs considered) and Leave to Construct applications. Any concerns can be considered on a case-by-case basis when an IRP Plan or Leave to Construct application comes before the OEB for approval.

When Enbridge Gas requests approval for an IRP Plan or a Leave to Construct, it will be necessary for Enbridge Gas to follow the requirements in the *Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario*[3] regarding Indigenous consultation, if applicable.

[3] Ontario Energy Board, Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario, 2016

8 IRPA COST RECOVERY AND ACCOUNTING TREATMENT PRINCIPLES

Costs for Enbridge Gas associated with IRP implementation fall into three categories:

- Incremental IRP administrative costs required to meet the increased workload related to IRP, including integrating IRP into Enbridge Gas's planning processes, completing the incremental stakeholdering, assessing identified system constraints for IRPA(s), and completing necessary IRP monitoring and reporting.
- IRPA Project costs including the planning, implementing, administering, measuring and verifying the effectiveness of specific investments in IRPAs.
- Ongoing operational and maintenance costs including the regular costs incurred to operate and maintain a specific IRPA investment after the project is in-service.

IRPA project costs, similar to the costs for infrastructure builds, will be eligible for inclusion in rate base where Enbridge Gas owns and operates the IRPA. Enbridge Gas should include in the project costs any physical assets acquired and costs directly attributable to the project consistent with how fixed assets are currently capitalized under US GAAP. Until rebasing, the associated revenue requirement of these project costs will be recorded in a capital costs deferral account for recovery annually or at rebasing as requested by Enbridge Gas.

Where Enbridge Gas proposes to make an enabling payment to a competitive service provider and does not own or operate the asset, these costs, if approved, will be included in the category of ongoing operational and maintenance costs and recovered as operating expenses. The OEB requires that Enbridge Gas select the most efficient and cost-effective option for its customers, between Enbridge Gas ownership and third-party ownership with an enabling payment. Until rebasing, these operating costs will be recorded in an operating costs deferral account for recovery annually or at rebasing as requested by Enbridge Gas. Incremental IRP administrative costs and other ongoing operational and maintenance costs will also be treated as expenses and recorded in this account.

The IRPA project costs eligible for inclusion in rate base will attract the same cost of capital as other rate based assets for Enbridge Gas. The depreciation period for the IRPA assets will align with the expected useful life of the asset, which will likely be the time over which the underlying IRPA is expected to provide peak load reduction.

Details about how these principles will be applied to specific IRPAs and IRP Plans will be determined in the IRP Plan applications. As part of an IRP Plan application, Enbridge Gas should provide details on which IRP Plan costs it believes are eligible for inclusion in rate base, versus those that should be considered operating expenses, with supporting rationale.

9 FUTURE IRP PLAN APPLICATIONS

When Enbridge Gas determines that an IRPA (alone, in combination with other IRPAs, or in combination with a facility project) is the best option to address a system need, it will apply for approval of an IRP Plan. The IRP Framework establishes a new approval process for IRP Plans, under section 36 of the OEB Act.

An IRP Plan approval from the OEB will operate as an endorsement of the IRP Plan, and approve the cost consequences. The costs would then be recovered, subject to a prudence review, through the IRP Costs deferral accounts annually and/or at Enbridge Gas's next rebasing application.

An IRP Plan approval will be mandatory if the forecast costs of the IRP Plan exceed the minimum project cost that would necessitate a Leave to Construct approval for a pipeline project (currently $2 million, proposed to increase to $10 million).

An IRP Plan application should include information similar to what is found in a Leave to Construct application, including:

- Purpose of the IRP Plan
- How the IRP Framework's guiding principles have been addressed
- Information on system need (forecast need/constraint being addressed)
- Discussion of alternatives (why the IRP Plan was selected, including the results of the economic evaluation)
- Description of the IRP Plan and IRPAs, including forecast impacts, costs, and implementation timing)
- Proposed approach to evaluation and monitoring
  - This could include a business case for any proposals for advanced metering infrastructure if this has not been assessed in Enbridge Gas's rebasing application
- Proposed approach to cost recovery (including details on costs Enbridge Gas proposes for inclusion in rate base, versus those that should be considered operating expenses, together with a supporting rationale)
  - Enbridge Gas should identify whether it intends to seek recovery of all or part of the IRP Plan costs, including rationale as to why these costs are incremental to activities included in existing rates
- Proposed approach to cost allocation (using the facility project that is being avoided, deferred, or reduced by the IRP Plan as a reference for the approach to cost allocation, as appropriate)

- In-service date, and any considerations that may apply regarding when the IRP Plan should be considered to be in-service such that Enbridge Gas is eligible for cost recovery
- Expected bill impacts
- Land and environmental issues (where relevant)
- A record of stakeholder engagement and Indigenous engagement and consultation (as appropriate)
- Conditions of approval

Prudently incurred costs associated with an approved IRP Plan will be eligible for cost recovery.

Enbridge Gas should seek approval for an adjustment to an IRP Plan, should the cost adjustment be an increase of greater than 25% of the approved cost. When seeking recovery of actual IRP Plan costs, Enbridge Gas will need to demonstrate that it has been prudent in managing its actions and resulting costs, as is typical for all requests for cost recovery.

Enbridge Gas will need to fully demonstrate the prudence of its actions particularly with regard to the risks of successful implementation of IRPAs and the potential for assets becoming stranded.

10 MONITORING AND REPORTING

Enbridge Gas shall file an annual IRP report with the OEB as part of its annual Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application, the proceeding in which it may seek disposition of balances in the IRP Costs deferral accounts.

The OEB does not intend to approve the annual IRP report, but it could impact the OEB's findings on the disposition of amounts in the IRP Costs deferral accounts, or inform future proceedings.

The annual IRP report and the report from the IRP Technical Working Group are to be filed for information regardless of whether Enbridge Gas is seeking approval to clear any balances in the IRP Costs deferral accounts.

The annual IRP report should include the following information:

- A summary of IRP stakeholdering activities from the past year
- A summary of IRP engagement or consultation activities with Indigenous peoples
- Updates on IRP pilot projects underway
- Updates on incorporating IRP into asset management planning
- Updates on status of potential IRP Plans
- Updates on status of approved IRP Plans, including details of adjustments made by Enbridge Gas
- Annual and cumulative summaries of actual peak demand reductions/energy savings generated by each IRP Plan to-date, including comparisons to the initial forecast reduction/energy savings and the actual amount of expenditure on each IRP Plan to-date
- The most recent results of Enbridge Gas's IRP Assessment Process for system needs, including reporting on those system needs where a negative binary screening or technical/economic evaluation resulted in no further assessment of IRPAs
- A summary of best available information on demand-side IRPAs, including types of IRPAs, estimates of cost, peak demand savings, status in Ontario, potential role and relevance to Enbridge Gas's system, and learnings from pilot projects and other jurisdictions
- Efforts taken to explore the use of interruptible rates for meeting system needs, including how customers have been provided the opportunity to consider this option
- Any other IRP-related matters established by the OEB.

11 IRP COSTS DEFERRAL ACCOUNTS

The OEB determined in the IRP Decision and Order that two IRP Costs deferral accounts will be established for the period from 2021 to 2023, to track incremental IRP-related costs not included in base rates during the current deferred rebasing term. Enbridge Gas will be preparing a Draft Accounting Order for the two IRP Costs deferral accounts, based on the guidance in the Decision and Order. Enbridge Gas will follow the approved Accounting Order for the use of these accounts.

Enbridge Gas may request disposition of account balances, when eligible, as part of its annual Non-Commodity Deferral Account Clearance and Earnings Sharing Mechanism application. Costs in the IRP Operating Costs Deferral Account for general IRP administrative costs may be brought forward for disposition without any prior approval. Costs in this account related to specific projects (e.g. project operating and maintenance costs, enabling payments to competitive service providers) should not be brought forward for disposition until an IRP Plan has been approved. When an IRP Plan has been approved and the project is considered to be “in-service”, Enbridge Gas is also eligible to seek cost recovery of the project’s capital-related revenue requirement through the IRP Capital Costs Deferral Account.

The balances brought forward for disposition in the IRP Costs deferral accounts should be based on actual expenditures. The balance for the IRP Capital Costs Deferral Account will include the revenue requirement impacts associated with project costs eligible for inclusion in rate base. The application to clear any balance in the IRP Capital Costs Deferral Account should describe the reasons for any variance between actual costs and the forecast costs that were included in the IRP Plan approval.

12 IRP PILOT PROJECTS

Enbridge Gas is expected to develop and implement two IRP pilot projects. The pilots are expected to be an effective approach to understand and evaluate how IRP can be implemented to avoid, delay or reduce facility projects.

The OEB expects that the IRP pilot projects will be selected and deployed by the end of 2022. The detailed consideration of IRP pilot projects should commence shortly after the issuance of the IRP Framework with input being sought from the IRP Technical Working Group.

The nature of the pilots should be responsive to the opportunities that arise. Enbridge Gas should then apply to the OEB for approval of the IRP pilot projects providing the information and following the approach for IRP Plans, described in chapter 9 ("Future IRP Plan Applications").

The implementation of pilots should not be a barrier to addressing a system need through a non-pilot IRP Plan, if an exceptional time-limited opportunity arises prior to the completion of the pilots.

Enbridge Gas should share key learnings from the pilots through reporting to the OEB and stakeholders, through the annual IRP report and more frequent updates to the IRP Technical Working Group, as needed. This experience will facilitate the development of other IRP Plans and identify areas for enhancement to the IRP Framework.

The IRP pilot project costs are to be tracked in the IRP Costs deferral accounts, and recovery can be requested annually for prudently incurred costs.

Enbridge Gas is encouraged to use the IRP pilot projects as a testing ground for an enhanced DCF+ test as discussed in section 5.3 ("Two-Stage Evaluation Process").